

Independent Power Projects in Africa: balancing development and investment outcomes

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Acronyms

ABB	Asea Brown Boveri
ADB	Asian Development Bank
AFD	Agence Francaise de Developpement
AfDB	African Development Bank
AFUDC	Allowance for funds used during construction
AKFED	Aga Khan Fund for Economic Development
ATJL	Artumas Tanzania (Jersey) Limited
Bcm	Billion cubic metres
BFI	Bilateral finance institution
BOAD	West African Bank for Development
BOO	Build own operate
BOOT	Build own operate transfer
BOT	Build operate transfer
BTO	Build transfer operate
CCGT	Combined cycle gas turbines
CDC	Commonwealth Development Corporation
CED	Compagnie Eolienne de Detroit
CIPREL	Compagnie Ivoirienne de Production d' Electricité
CMS	Consumer Michigan Services
COD	Commercial operation date
CPI	Consumer Price Index
CUE	Cost of unserved energy
DEG	German Investment & Development Corporation
DFI	Development finance institution
DFID	Department for International Development
DRC	Democratic Republic of Congo
EAP	East Asia and Pacific
ECA	Europe and Central Asia
EDF	Electricité de France
EEHC	Egyptian Electricity Holding Company
EETC	Egyptian Electricity Transmission Company
EIA	Environmental Impact Assessment
EIB	European Investment Bank
EPC	Engineering, procurement, and construction
ERA	Electricity Regulatory Authority (of Egypt)
ERB	Electricity Regulatory Board (of Kenya)
ESI	Electricity supply industry
EWURA	Energy and Water Utilities Regulatory Authority (of Tanzania)
FDI	Foreign direct investment
FMO	Netherlands Development Company
GDP	Gross domestic product
GNI	Gross national income
GoE	Government of Egypt
GoK	Government of Kenya
GoT	Government of Tanzania
HFO	Heavy fuel oil
IADB	Inter-American Development Bank
ICB	International competitive bid
IDA	International Development Association
IFC	International Finance Corporation
IMF	International Monetary Fund
IPO	Initial public offering

IPP	Independent power project
IPS	Industrial Promotion Services
IPTL	Independent Power Tanzania Limited
ISO	Independent system operator
ISP	Independent service provider
IT	Information technology
JV	Joint venture
JBIC	Japan Bank for International Cooperation
KenGen	Kenya Generating Company Limited
km	kilometre
KPLC	Kenya Power and Light Company
Ksh	Kenyan shilling
kV	kilovolt
kVa	kilovolt ampere
kW	kilowatt
kWh	kilowatt hour
LAC	Latin America and Caribbean
LIBOR	London Intebank Offered Rate
LNG	Liquefied natural gas
Mcf	Million cubic feet
MDG	Millennium development goal
MEP	Mtwara Energy Project
MFI	Multilateral finance institution
MIR	Management Programme in Infrastructure Reform and Regulation
MMBtu	Million British thermal units
MMcfd	Million cubic feet per day
MW	Megawatt
O&M	Operating and maintenance
OCGT	Open cycle gas turbine
OECD	Organization for Economic Cooperation and Development
ONE	Office Nationale de l'Electricité (of Morocco)
OPIC	Overseas Private Investment Corporation (of the United States)
QoS	Quality of supply
PEL	Pendekar Energy Limited
PESD	Program on Energy and Sustainable Development
PHCN	Power Holding Company of Nigeria
PPA	Power purchase agreement
PPI	Private participation in infrastructure
PRG	Partial risk guarantee
PRI	Political risk insurance
PROPARCO	Promotion et Participation pour la Cooperation economique
PSCR	Parastatal Sector Reform Commission (of Tanzania)
PSEG	Public Service Enterprise Group
PURPA	Public Utility Regulatory Policies Act
ROE	Return on equity
RSA	Republic of South Africa
SA	South Asia
SAPP	Southern African Power Pool
SEEB	Société d'Electricité d'El Biban
Sida	Swedish International Development Cooperation Agency
SSA	Sub-Saharan Africa
STEG	Société Tunisienne d'Electricité et du Gaz
T&D	Transmission and distribution
TANESCO	Tanzania Electric Supply Company Limited
TAQA	Abu Dhabi National Energy Company

Tcf	Trillion cubic feet
TDFL	Tanzania Development Finance Company Limited
TPDC	Tanzania Petroleum Development Corporation
Transco	Transmission company
TSO	Transmission system operator
TWh	Terawatt hour
UK	United Kingdom
USA	United States of America
VAT	Value added tax
VIP	VIP Engineering Limited
VRA	Volta River Authority
WDI	World Development Indicators
YFP	Yinka Folawiyo Power Limited

Abstract

In the early 1990s, a new model emerged for the provision of electricity generation across developing regions. The model involved private sector participation in the form of independent power projects (IPP). Driving this change in business was insufficient public finance from host country governments, a reduction in concessionary loans from multilateral and bilateral development institutions, and a push for improved efficiency in a state-owned utility sector that was considered to be underperforming. This dissertation reviews how IPPs developed across both North Africa and Sub-Saharan Africa. The analysis focuses on the extent to which positive development outcomes (viz. reliable and affordable power) and investment outcomes (viz. favourable investment returns and the opportunity to grow investments) were both achieved. The dissertation posits that balancing development and investment outcomes leads to greater sustainability for projects. It further explores a range of elements that contribute to the success of projects, namely: the investment climate; policy, regulatory and planning frameworks; competitive procurement practices; availability of competitively procured fuel; favourable debt and equity arrangements, including new trends in the nature of IPP firms and credit enhancement arrangements; and new risk management techniques. In-depth case studies of IPP experiences in Egypt, Kenya and Tanzania are used to explore the question of balancing outcomes and sustainability. Reviews of IPP experiences in Cote d'Ivoire, Ghana, Morocco, Nigeria and Tunisia also supplement the analysis together with an evaluation of the foreign direct investment context and related theory. Framing the whole discussion is an examination of how the new model for electric power provision evolved and how power sector reform models need to be adjusted to better reflect the reality in developing countries and emerging economies.

Acknowledgments

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Chapter 1

Introduction

1.1 Statement of the problem and research objective: IPPs in Africa

At the beginning of the 1990s, virtually all major power generation throughout Africa was financed by public coffers, including via concessionary loans from development finance institutions (DFI).¹ These publicly financed generation assets were considered one of the core elements in state-owned, vertically integrated power systems. In the early 1990s, however, a confluence of factors brought about a significant change in business. With the main drivers identified as insufficient public funds for new generation and decades of poor performance by state-run utilities, developing countries throughout Africa began to adopt a new model for their power systems, influenced by pioneering reformers in the United States of America (USA), the United Kingdom (UK), Chile and Norway. Urged on by multilateral and bilateral development institutions, which largely withdrew from funding state-owned projects, a number of countries adopted plans to unbundle their power systems and introduce private participation and competition. Independent power projects (IPP), namely privately-financed, greenfield generation, supported by non-recourse or limited recourse loans, with long-term power purchase agreements (PPA) with the state utility or another off-taker, became a priority within overall power sector reform (World Bank 1993a:45,51; World Bank and USAID 1994:1). IPPs were considered a quick and relatively easy fix to persistent supply constraints, and could also potentially serve to benchmark state-owned supply and gradually introduce competition (APEC Energy Working Group 1997). IPPs could be undertaken before sector unbundling. An independent regulator was also not a prerequisite since the PPA laid down a form of regulation by contract.

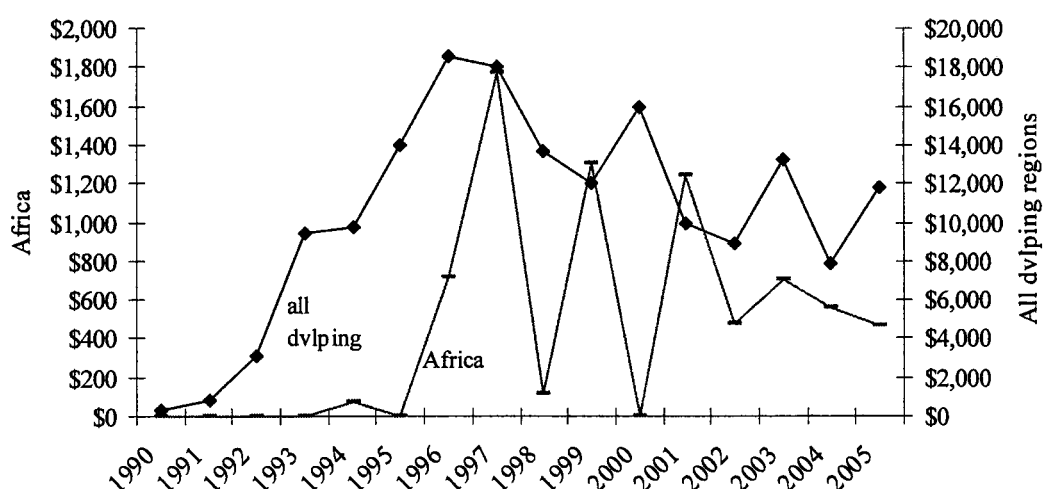
In 1994, Cote d'Ivoire became among the first African countries to attract a foreign-led IPP to sell power to the grid under long-term contracts with the state utility. Cote d'Ivoire kicked off its IPP development with a 210 megawatt (MW) combined cycle gas-fired plant undertaken by Saur International and Electricité de France (EDF). Five years later, the country

¹ The term 'multilateral development institutions' (MDI) is used throughout this thesis to refer to such organizations as the World Bank Group (including the International Development Association (IDA), International Finance Corporation (IFC), Multilateral Investment Guarantee Agency (MIGA) and International Bank for Reconstruction and Development (IBRD)), Inter-American Development Bank (IADB), Asian Development Bank (ADB) and other regional banks. The term 'bilateral development institutions' (BDI) is used to refer to bilateral funding agencies, such as the UK Department for International Development (DFID), the Commonwealth Development Corporation (CDC), the Investment and Promotions Company for Economic Cooperation (PROPARCO) and the United States Agency for International Development (USAID), which are distinct from Export Credit Agencies (ECA), for which funding is directly tied to exports. The term 'development finance institutions' (DFI) will be used throughout to refer to all such multilateral and bilateral organizations.

would build West Africa's largest IPP, Azito, at 330 MW.² Egypt also became a magnet for private sector investment, with InterGen and EDF winning tenders to build approximately 2000 MW of power. Ghana, Kenya, Morocco, Tanzania and Tunisia, among others, also opened their doors to foreign and local investors. In 1997, later seen as the peak of investment, there was a record US\$1.8 billion in IPPs in Africa (World Bank 2006c).

Although IPPs were considered part of a larger power sector reform programme, reforms were not far reaching. In most cases, state utilities remained vertically integrated and maintained a dominant share of the generation market, with private power invited only on the margin of the sector.³ Policy frameworks and regulatory regimes, necessary to maintain a competitive environment, were limited. International competitive bids (ICB) for those IPPs that were developed were often not conducted due to tight timeframes, resulting in limited competition *for* the market and, due to long-term PPAs, no competition *in* the market. These long-term PPAs and often government guarantees and security arrangements, such as escrows and liquidity facilities, exposed countries to significant exchange rate risks. Finally, while Africa has seen private participation in greenfield electricity projects continue, private investments have not achieved the levels of the late 1990s, with 1997 representing the zenith as illustrated below.

Figure 1.1: Greenfields IPPs in Africa vs. all developing regions (US\$ million)



Source: based on author's compilation and Private Participation in Infrastructure Database (World Bank 2006c)

Note: Africa figures include only greenfield electricity projects in North Africa and Sub-Saharan Africa whereas world figures include both greenfield electricity and natural gas projects (however electricity projects account for 84 per cent of the total value).

² In terms of size, Azito has since been superseded by another West African plant, the 450 MW Okpai IPP in Nigeria, which came online in 2005. The largest IPP in Africa is, however, Morocco's Jorf Lasfar, a 1360 MW coal-fired plant, which will be discussed in section 3.4.1.

³ Exceptions are Cote d'Ivoire, Morocco and Tanzania, where independent power projects contribute significantly (more than 50 per cent) to overall electricity production.

Several factors explain the recent trends in investment. Private sector firms were deeply affected by the Asian and subsequent Latin American financial crises. The Enron collapse and its aftershocks also featured prominently in influencing American and European-based firms to reduce risk exposure in emerging and developing country markets and refocus on core activities at home. Furthermore, DFIs began to reconsider their position of restricted infrastructure investment, which had predominated throughout the 1990s. As concessionary funding became available again, many countries opted for publicly funded projects, rather than their private sector counterpart, such as Egypt, which has seen its current five year power investment implemented by the incumbent, state-owned utility, and supported entirely by concessionary loans.

Despite this revival of concessionary lending for power projects, investments are insufficient to address Africa's power needs, with only 25 per cent of the population presently with electricity access, and poor supply the rule, not the exception. With the original drivers for market reform still present, involvement of the private sector appears to be an inevitable part of the future.

This thesis analyzes the experience of IPPs in Africa in order to understand how more positive development and investment outcomes may be achieved for the spectrum of public and private stakeholders to ensure the long-term sustainability of projects. Positive development outcomes are considered here as generally reliable and affordable power for the host country, while positive investment outcomes are roughly defined as satisfactory returns on investments and new investment opportunities. It should be noted that the definition of sustainability adopted by this thesis relates purely to whether contracts and projects endure (i.e. are not abandoned) and whether plants continue to produce power over the long-term; no attempt is made to consider IPP sustainability with regard to larger development goals.^{4 5}

The empirical data unearthed by this thesis, based largely on case studies of IPPs in Egypt, Kenya and Tanzania, seeks to deepen knowledge and understanding of existing bodies of work related to power sector reform and the obsolescing bargain theory (within the area of foreign direct investment, FDI).⁶ Building on the literature related to IPPs, this thesis then aims to advance a new framework for understanding the sustainability of IPP investments.

⁴ Neither the use nor the definition of development outcomes and investment outcomes is unique to this thesis. What is, however, unique is the in depth analysis of such outcomes within the context of African IPPs. References to development and investment outcomes include Manibog (2003:22-25) and Victor (2004:11-13).

⁵ Undoubtedly, there is overlap between the development and investment outcome, particularly when it comes to local investors who may be considered to be directly related to both outcomes.

⁶ According to the theory of the obsolescing bargain, which will be explored in greater depth in Chapter two, if unequal bargaining power results in the deal inordinately favouring the investor, then once the concrete is poured and equipment bolted down, there is a risk of the host country expropriating the project in part or in full. The original investment deal (the bargain) thus may become obsolete,

1.2 Key research questions

Do IPP contracts endure when affordability and reliability of power come at the expense of reasonable investment returns and vice versa, or does achieving a balance between development and investment outcomes significantly improve the sustainability of IPPs? If so, what are the steps to striking and protecting such a balance? This thesis posits that balancing outcomes is indeed the key to sustainability⁷, and attempts to offer a different and more realistic framework for power sector reform.

The thesis aims to take the understanding of IPPs one step forward by exploring what elements contribute to both successful development outcomes and investment outcomes, given a suite of exogenous stresses, including macroeconomic shock and currency devaluation, drought and civil strife. How, for instance, does *a favourable investment climate* impact directly on outcomes? What is the relationship between *a clear power sector policy framework* and outcomes? Does *clear, consistent and fair regulatory oversight* hold the key to balanced outcomes and project sustainability? Or does the solution to sustainable project outcomes lie in *coherent power sector planning, competitive bidding practices, and/or abundant low cost fuel*.

Each of the abovementioned elements (in italics) relate primarily to the host country purview, which may be linked most directly, although not exclusively, to development outcomes. In addition, this thesis will undertake a review of elements that relate to the project purview, which in turn relate primarily to investment outcomes, including inquiring into the relationship between sustainable outcomes and the following: *favourable equity arrangements, favourable debt arrangements, secure and adequate revenue streams, other risk management and mitigation measures, secure fuel arrangements, positive technical performance and ongoing strategic management and relationship building*.⁸

Although virtually all of these elements have been discussed before within the growing body of power sector reform literature, there exists no work in which such elements are evaluated systematically within the African context and within the broader framework of development and investment outcomes, the obsolescing bargain theory and power sector reform. This thesis, through a systematic treatment of these elements, seeks to reveal new insights and trends that are important not only for the future sustainability of IPP investment in Africa—but also for revising the broader literature and theoretical framework for understanding and advancing power sector reform and investments in developing countries.

particularly in those investments that involve large fixed capital, which is typical in infrastructure projects.

⁷ As noted in the Introduction, sustainability is defined narrowly by this thesis, namely whether projects endure (i.e. are not cancelled) and whether power is produced over the long-term.

⁸ The list of elements has emerged from several in depth country case studies, as will be described in greater detail under Methodology below (section 1.3.3).

1.3 Methodology

The literature and relevant theory provide an analytical framework within which empirical data and experience may be better understood. Furthermore, analysis of new empirical data may result in a deepening or a modification of existing theoretical frameworks, which this thesis seeks to do.

1.3.1 Foray into the literature and relevant theory

The question of IPP sustainability was first addressed by this thesis in relation to the power sector reform context. Through an in-depth literature review as well as interviews with key authors, this thesis documents how a standard model for power sector reform emerged (including specifications for IPPs), which took on the status of a theoretical framework within which experience could be understood as well as a template for advocating future actions. A review was also undertaken of a small part of the foreign direct investment literature as it applies to large infrastructure projects such as IPPs, namely the obsolescing bargain. An inquiry into the relevance of the obsolescing bargain theory, which (as noted in footnote 6) posits that if the original investment is made on seemingly unequal terms, there is a strong likelihood that the balance will shift in favour of the host country government over time. This theory was considered potentially helpful to predict both investor and host country behaviour. Simultaneously, a review of existing IPP literature was undertaken, including work led by the Program on Energy and Sustainable Development (PESD) at Stanford University, which included a multi-year, 13 country study that surveyed 34 IPPs.⁹ Not only did the Stanford PESD IPP study inform this thesis' inquiry related to the obsolescing bargain, as noted above, it also influenced the research approach and ultimately helped to guide the research questions, as will be examined in greater depth immediately below as well as in Chapter two.

Collectively these surveys of relevant literature and related theories in turn informed the empirical analysis and helped to formalize definitions of development and investment outcomes as well as contributing elements to success that form the basis of the key research questions.

⁹ The Stanford PESD IPP study referred to here was carried out primarily by Erik J. Woodhouse, under the guidance of David Victor and Thomas C. Heller of Stanford's PESD. An interim report was published (in Woodhouse, 2005), as were the main project findings (in Woodhouse, 2006a). In addition, a synopsis of development and investment outcomes for each of the country studies was released (in Woodhouse 2006b) as well as an abridged version of the paper (in Woodhouse 2006c). The work, spanning over two years, was based on over a dozen country studies conducted by over a dozen researchers including both Anton Eberhard and Katharine Nawaal Gratwick, based at the University of Cape Town's Management Programme in Infrastructure Reform & Regulation (MIR). 'Stanford PESD IPP study' is the chosen designation for the body of work throughout this thesis, with credit given in text referencing to the primary author of each of the different research pieces.

1.3.2 The cases

The empirical work focused on IPP investments in Africa. First, the full universe of IPP projects was identified. At that time (in November 2004), it was found that three countries—Egypt, Kenya and Tanzania—had at least three IPPs on the ground, and accounted for nearly half of the approximately 6000 MW of total IPP capacity installed in Africa. These three countries were selected for in-depth case studies and fieldwork, based on the rationale that projects within countries may be contrasted to enhance understanding as well as projects both within and outside different regions in Africa.

Since the inception of the research in late 2004, the pool of IPPs has expanded. As of 2005, Morocco also boasts three IPPs. Furthermore, several of those countries with less than three IPPs have emerged with important lessons to tell. Therefore, although Egypt, Kenya and Tanzania are the basis for the majority of the empirical data and the countries in which primary research was carried out, IPP experiences in Cote d'Ivoire, Ghana, Morocco, Nigeria and Tunisia are also summarized.¹⁰ In this larger sample, each country has a minimum of two IPPs,¹¹ which continues to allow for analysis across projects in any given country. By end-2006, together these eight countries represented 80 per cent of the installed IPP capacity and 75 per cent of IPP investments in Africa (World Bank 2006c). Although this sample accounts for most of the African IPP capacity and investment, it is nonetheless still a limited sample, with only eight countries and less than 20 projects.¹²

Finally, this project tally takes into consideration neither any state-sponsored plants, which may be deemed 'independent' from the utility, nor emergency power plants. The latter, namely, mostly smaller plants leased by utilities for one to two years to plug shortages, stand in contrast to the IPPs as previously defined as greenfield generation investment, with long-term PPAs with state utilities or other off-takers, supported by non- or limited recourse loans. Such projects will be mentioned only insofar as they impact directly on IPP outcomes, including how for instance they may affect the investment environment. It should, however, be noted that emergency plants have become increasingly visible, particularly since the inception of power sector reforms, which focus on the introduction of private sector participation.

¹⁰ It should be noted that this research was part of a broader assessment of African IPPs undertaken by MIR, that went beyond those studies included in the Stanford PESD analysis, noted in footnote 9. The author of this thesis has also been a co-author of reports on Morocco (Malgas, Gratwick et al. 2007a) and Tunisia (Malgas, Gratwick et al. 2007b), as well as forthcoming reports on Cote d'Ivoire (Malgas, Gratwick et al. 2007c) and Ghana (Malgas, Gratwick et al. 2007d). In addition, an as of yet unpublished survey of Nigerian IPPs was conducted by the author of this thesis in collaboration with researchers at the Centre for Energy Research and Development at Obafemi Awolowo University in Ile-Ife, Nigeria.

¹¹ As will be discussed in section 3.4.3, only one of Ghana's three intended IPPs has produced electricity.

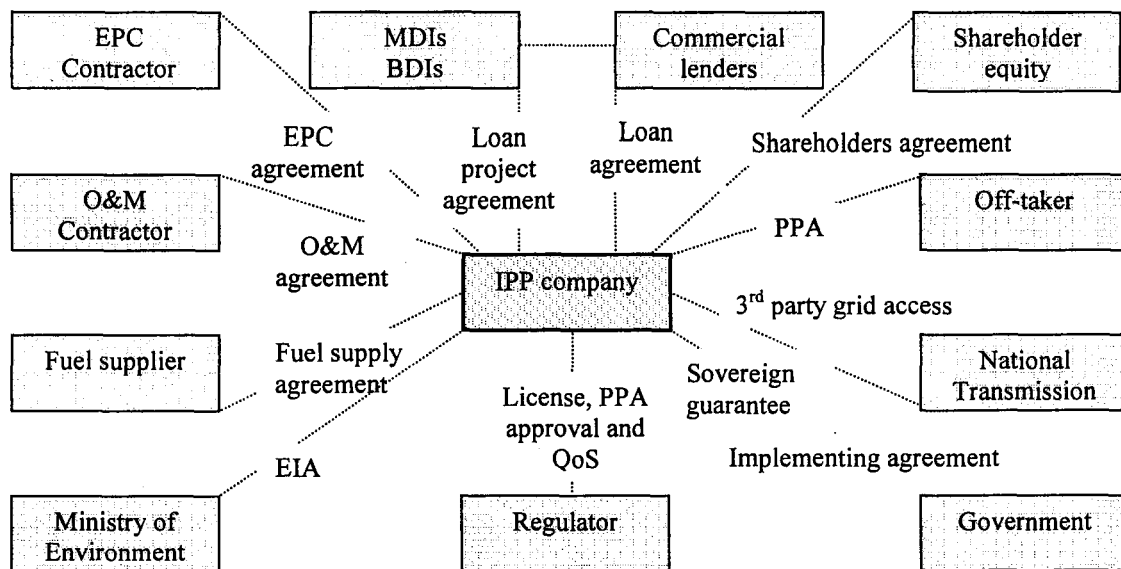
¹² Due to limited time and resources, cases (and the requisite field work to map the case studies) have been limited to three in depth studies as well as three country overviews, rather than canvassing all African countries with IPPs; extreme care has, however, been taken in selecting countries and carrying out field work to ensure that they are representative of the pool.

1.3.3 Sifting facts and triangulation

An inductive research approach was adopted at the outset, which involved initially conducting a review of relevant country and project documentation. Field studies were then carried out in January, November and December 2005, in Egypt, Kenya and Tanzania, which involved in-depth meetings with key stakeholders involved in IPPs. Interviews were also conducted via numerous conference calls to each of the focus countries as well as to relevant stakeholders in Washington, D.C., London and Israel. Where available, performance data was also compiled.

The Figure immediately below depicts the primary stakeholders in a generic IPP deal. The terms and conditions that define the relationships between such stakeholders are generally spelled out in, among others, the: shareholders agreement, power purchase agreement, engineering, procurement, and construction (EPC) agreement, operating and maintenance (O&M) agreement, loan agreements, intercreditor agreements, and security documentation, including sovereign guarantees from government to the IPP company as well as guarantees provided by multilateral and bilateral development institutions (Marais 2006:1; Sinclair 2007:5-15).

Figure 1.2 Primary stakeholders and contracts in an IPP deal



Source: adapted by author from Ferreira (2004:5) and Sinclair (2007:5-15)

Notes: MDI: multilateral development institution; BDI: bilateral development institution; EIA: Environmental Impact Assessment; QoS: Quality of Supply.

The first step was to understand the extent to which stakeholders deemed that favourable development and investment outcomes were achieved (viz., the required power was delivered reliably and cost-effectively, and targeted rates of return and expectations of expanding

investment were attained) and whether outcomes were in balance and ultimately seen as sustainable or enduring. Performance data provided by stakeholders was also critical in reaching conclusions about outcomes. Although attempts were made to gather information from all major stakeholders, research focused on the IPP company and the off-taker. The next step was to identify, also primarily through stakeholder interviews, the elements that could explain outcomes, including by grouping elements into country level and project level factors. While this process of identifying and articulating contributing elements was informed by Stanford PESD's research on IPPs, this thesis made a clear departure from the PESD framework, which focused on explaining the variation in IPP outcomes through a series of five hypotheses, as explained in detail in section 2.7.2.

The data gathering phase involved extensive triangulation. First, the diverging views of different stakeholders were raised throughout the interviews, without divulging names, in an attempt to identify the general consensus. Second, original interview transcripts were sent back to each stakeholder to verify the content. Third, comments were sought from all major stakeholders on the final analysis. Wherever possible data provided by stakeholders was verified with published sources as well. This data collection process, involving both primary and secondary sources, spanned between six months and one year, depending on the country, and the author of this thesis went back to stakeholders no less than half a dozen times. Since this time, to follow up on new developments, correspondence and telephone exchanges continue to be conducted regularly, along with gathering new performance data—with data triangulation to verify comments also ongoing. Most data is current through May 2007.

The example of research in Tanzania, detailed here, is representative of the approach adopted in each of the countries. Over 30 interviews were conducted with more than 20 stakeholders in January, February, August, November and December 2005 in Dar-es-Salaam and via teleconference in Washington D.C. and London. Interviews were followed by email correspondence to clarify discussion points. Details presented on IPPs and reforms were also confirmed across a range of sources. Stakeholder interviews included present and former directors and managers at Orca Exploration, Independent Power Tanzania Limited (IPTL), Songas, Ministry of Energy and Minerals (MEM), Energy and Water Utilities Regulatory Authority (EWURA), Parastatal Sector Reform Commission (PSRC), Tanzania Petroleum Development Corporation (TPDC), VIP Engineering Limited (VIP), Tanzania Electric Supply Company Limited (TANESCO), NETGroup Solutions, Swedish International Development Cooperation Agency (Sida), and the World Bank. TANESCO provided the majority of the performance data.

Due to sensitivity of data, the names of stakeholders, who have been the primary source of data for this thesis, have largely been left out of the discussion; most stakeholders are only identified, if at all, by organizational affiliation in the text. As a result, much of the data, which

Chapter 2

Contextualizing IPPs: power sector reform and FDI

IPPs emerged in the context of power sector reforms, which were driven by the need for new investment and improved sector performance. A second key contextual feature was the foreign direct investment experience of previous decades. Both of these contexts have been mapped out in bodies of literature. In this Chapter, this thesis undertakes to review significant portions of this literature in order to provide a theoretical context for an analysis and understanding of independent power projects. Building on literature that documents the IPP experience as well, the Chapter culminates by introducing a new analytic framework for understanding IPP outcomes.

2.1 Power sector reform overview

For diverse reasons in the 1970s and 1980s, a number of different countries, primarily from the industrialized world, began to make changes to the way they operated their electric power systems.¹⁴ The changes these countries made were by no means uniform, and often were driven by ideology. Then, through a process of trial, error, research, writing and policy formation, a gradual understanding developed of the different elements of reform, which in turn were grouped into different categories. These categories subsequently became to be viewed as the building blocks of a standard model for power sector reform. The model did not represent the reform paths of the countries exactly but was considered to be both a general ideal for reform as well as an analytic framework to understand and characterize reform processes in different countries. This model was then taken up by a number of stakeholders working in less developed countries (from DFIs, to consultants and local policy makers) and, in certain instances, written into policy frameworks thereby codifying the standard model. While there are a range of opinions about the appropriateness of the recommendations, in no African country have reforms actually been undertaken in full. This section highlights the developments that led to how power sector reforms came to be defined as a standard model and theoretical framework in its own right as well as reviews how the model and framework were implemented and with what effect, including most importantly, with the regard to IPPs.

¹⁴ The one exception was Chile, as discussed later in section 2.3.2, which, although categorized as a developing country due to its per capita gross domestic product (GDP), rated high in terms of electricity access (in contrast to most developing countries), with approximately 98 per cent of urban households and about 62 per cent of rural ones with access, prior to sector reform in the late 1980s (Fischer and Serra 2003).

forms the basis of Chapters four through six, is not cited. In certain instances, however, where stakeholders have indicated their willingness, citations do include names and the designation of “per com” for personal communication.

1.3.4 Ultimate goals

This thesis summarizes the country data, and then analyzes it within the context of the contributing elements of success, with three primary goals. First, the analysis seeks to illuminate the main question. That is, does balancing development and investment outcomes indeed yield more sustainable projects?¹³ Secondly, the analysis aims to extend and deepen the analytic framework (of stresses and contributing elements to success) to better understand outcomes and which elements contribute to success and failure. Finally, it is the goal of the analysis to reflect on the theoretical framework, namely what does such analysis reveal about the obsolescing bargain theory, IPPs and power sector reform.

1.4 Outline of thesis

Following this brief introduction, Chapter two identifies the main theoretical areas that inform the analytical framework of this thesis, namely the role of IPPs within power sector reform and the role of the obsolescing bargain (within the context of FDI). Chapter three offers an overview of the African IPP experience, reviewing general investment and electricity conditions on the continent before, during and after the first IPPs. In Chapter four, the first country case, there is an extended discussion of how IPPs unfolded in Egypt. Chapter five introduces the contrast of Sub-Saharan African cases by recounting how IPPs developed in Kenya. This in turn is followed by a discussion in Chapter six of the case of Tanzania’s IPPs. In Chapter seven, a summary of findings is provided and conclusions drawn, which intend to deepen knowledge and understanding, and expound on implications for power sector reform and future IPP investments.

¹³ It should be noted here that although tools for measuring investment gains are limited (rates of returns are often confidential), efforts have been made to obtain as much information as possible, including the extent to which investors are making additional, similar investments, to adequately judge investment gains.

2.2 Power history in brief: market forces once and again

Although the push for private sector participation in the power sector was a departure from the status quo that predominated in most developing countries in the early 1990s, it was not unprecedented. Throughout the end of the nineteenth century and early twentieth century, the electricity supply industry (ESI) and other infrastructure industries such as water, transport and some telephone services, across North America, Europe and parts of South America, Africa and Asia, developed largely within free market conditions (Kessides 2004:27). The Pearl Street Station, the first central power station, pioneered by Thomas Edison in 1882 in New York City, was the result of privately-financed and privately-managed efforts (Neil 1942:322). In the same year in South Africa, private public partnerships would lead to the first electric street lights in the mining town of Kimberly, and later more widespread electrification, which helped fuel commercial and industrial development (Steyn 2006:11; Eberhard 2007:218).

While the initial push was private, it was not long before deeper government involvement was evidenced. This occurred with varying degrees across countries, especially after World War II. The rationale was four-fold. First, the network component of the ESI was, after considerable trial and error, classified, as a natural monopoly. That is, one firm was thought to produce goods less expensively than if there were multiple firms in the market, as average costs declined as output increased (Joskow and Schmalensee 1983:29-20; Newbery 2001a:1-2).¹⁵ Government ownership of the monopoly (or public regulation) was often justified on the grounds that the state was the custodian of the public interest and therefore would be the least likely to act in an opportunistic manner, as monopolists were prone to do. Secondly, with regard to public ownership of the generation component, the general argument was based on the fact that significant amounts of capital were needed, as increasingly large plants were built to capitalize on economies of scale. The state was often asked to guarantee these investments and became progressively directly involved through state-owned enterprises. Thirdly, ownership by one sole firm (government) also helped to ensure the necessary coordination among the different segments (generation, transmission and distribution). Finally, an overarching argument was made about the strategic nature of the ESI, especially for industrial development, which justified state ownership and operation (Yergin and Stanislaw 2002:7).

Electric power activities thus were vertically integrated, which meant one supplier provided generation, transmission and distribution services to a given area (Hunt 2002:2,24). The only real variation evidenced was whether the monopolies were publicly or privately controlled, with the United States, Germany and Japan, all exhibiting significant private

¹⁵ This conclusion was drawn only after, however, a number of countries had experimented with having multiple owners and operators of the network component, which was deemed to result in inefficiency (Yergin and Stanislaw 2002:7).

ownership, albeit heavy government regulation of the industry—but most countries opted for public ownership (Kahn 1988:3; Bacon 1995b:120,121; Patterson 1999:124).

By the 1970s and 1980s, however, a number of political, financial and technical factors converged and started to chip away at the logic that electricity provision should be handled via a vertically integrated generally state-owned monopoly. Although not an exhaustive list, five of the major factors are summarized here. First, there was a growing movement away from public sector ownership especially in the UK and Chile, largely due to ideological reasons (Bacon 1995b:120).¹⁶ Secondly, as gas-fired combined cycle gas turbines (CCGT) and other smaller, more modular technologies came on the market, capital costs of plants declined, along with the need for government guarantees, making them more easy to finance (Hunt 2002:26-27; Victor and Heller 2007:3). Thirdly, development of information and communication technologies enabled the electricity system to be organized and controlled without vertical integration. Fourth, there was increasing doubt of the efficiency of the highly regulated privately-owned but vertically integrated utilities (particularly in the USA) (Bacon 1995b:120). Finally, publicly-owned utilities in most developing countries were exhibiting persistent poor performance and governments were either unwilling and/or unable to provide further capital investment. These factors prompted a move toward private participation and competition (for the non-natural monopoly components of the system), which was expected would yield improved and less costly electricity supply (Bacon 1995b:121; Wolak 1998:81).

2.3 Powering ahead: the first reforms and reformers

The reform of ESIs was piecemeal and varied, with the front-runners—USA, Chile, England and Wales and Norway—summarized below, each tackling the challenge in a slightly differently way.¹⁷ These reforms were based largely on untested theory (Patterson 1999:124; Manibog, Dominguez et al. 2003:50) and would later be brought to bear on countries throughout the developing world (Bacon and Besant-Jones 2002:6).

¹⁶ Under the Conservative government of Margaret Thatcher, approximately 40 public companies were privatized. Initially, privatization was sought simply to reverse recent nationalizations, however, eventually the objective included reducing the hold of the unions as well as improving economic efficiency, which the Conservatives believed was being hampered by public ownership (Newbery 2001a:9-16). One target was the coal miners' union. Restructuring and privatizing the electricity industry would introduce competition, including buying coal from other sources and introducing new fuels, such as gas. In Chile, privatization was led by a Augusto Pinochet together with the Chicago Boys (a group of policy makers, schooled in the free-market economics of Milton Friedman, at the University of Chicago). A rash of privatizations were carried out between 1973 and 1990, corresponding with Pinochet's rule, which, like in the UK, went well beyond returning nationalized assets to private hands (Collins and Lear 1991).

¹⁷ This description of the early, largely Organization for Economic Cooperation and Development (OECD) reformers, does not purport to be an exhaustive review of developments. For more extensive and up-to-date coverage, see, among others: Newbery (2001a), Joskow (2003), Littlechild (2005) and Sioshansi (2006).

2.3.1 United States

In 1978, the USA adopted the Public Utility Regulatory Policies Act (PURPA), which required utilities to purchase electricity, at their avoided cost, from “qualifying facilities”, which comprised mainly cogenerators and small power producers (International Energy Agency 2001:29; Hunt 2002:257). The overarching goal of PURPA was to enhance energy security and environmental protection by promoting more thermally efficient cogeneration plants as well as renewable technologies (Joskow 2001:12). This legislation set in motion a new way of business, and by 1992, IPPs in the USA accounted for 60 per cent of the new capacity (World Bank 1993a:42; Hunt 2002:257). The plants thus were important agents of change in terms of adding new capacity and introducing new (greener) technology (Hunt 2002:257). *New text:* The next major development in the USA occurred in 1996 when the Federal Energy Regulatory Commission (FERC) ordered third party access to the transmission system, a requirement set forth in the 1992 Energy Policy Act passed by the US Congress (Federal Energy Regulatory Commission 1996). This in turn facilitated wholesale competition as numerous large power exchanges, managed under non-profit regulated independent system operators (ISO), were established (O'Neill, Helman et al. 2006:480). As of 2006, six wholesale markets account for over half of the country's load. Meanwhile retail competition has spread to less than half the states, with switching evidenced primarily by commercial and industrial users (Sotkiewicz 2006:18-19).¹⁸

2.3.2 Chile and Argentina

The same year that the PURPA legislation was passed in the United States, the National Energy Commission (CNE) was established in Chile, which led to a series of power sector reforms aimed at increasing efficiency. The General Law of Electric Services of 1982 was among the next significant steps, which stipulated third party access to transmission (well ahead of the USA's third party access) and defined the Economic Load Dispatch Centre (CDEC) as Chile's ISO (Raineri 2006:77). The 1982 Law also served to unbundle the two state-owned utilities, ENDESA and Chilectra. Privatization took hold gradually (World Bank 1993a:70). By 1991, the ESI consisted of 11 generating companies and 21 distribution companies, as well as two integrated companies—virtually all privately owned (Newbery 2001a:119-120). Since 1982, Chile has adopted wholesale and retail competition, with the latter phased in slowly (and since 2004 available for consumers of greater than 500 kilowatt, kW). Most small consumers continue to pay regulated prices (set by the Ministry of Economy, with input from CNE) (Raineri 2006:78; Sotkiewicz 2006:5).

¹⁸ No attempt is made to discuss the intricacies of the California market or related challenges encountered in wholesale and retail trading, which is covered in: Besant-Jones and Tenenbaum (2001), Wolak (2003), and Sweeney (2006:319-381).

Although Chile was the pioneering Latin American country to reform its ESI, Argentina is also mentioned here briefly, primarily due to its connection to the developing countries assessed in this thesis. Argentina's reforms followed immediately on the heels of Chile, with the unbundling of the sector followed by the privatizing of generation, transmission and distribution (Dyner, Arango et al. 2006:595-616; Woodhouse 2006a:143). Important elements of Argentina's reform include on the one hand the lengthy and comprehensive consideration of the reform program before enactment and on the other hand the speed with which it was ultimately conducted, with an electricity market established within a two year period, following the enabling legislation (passed in 1989) (Besant-Jones 2006:25; Dyner, Arango et al. 2006:604).¹⁹

2.3.3 England and Wales

A decade after reforms took off in Chile, the UK would embark on its own radical reform. In 1989, England and Wales passed an electricity act, which provided the legal framework for restructuring and regulation (Newbery 2006:109,115). Important characteristics of the ESI at the time included the central role of the UK's nationalized coal industry, which sold approximately three-quarters of its supply to the electricity sector and accounted for almost 70 per cent of the primary fuel for power generation. Another defining feature, which complicated restructuring, was a fleet of nuclear plants that were deemed non-commercial (nuclear accounted for approximately 20 per cent of fuel for power generation) (Newbery 2006:111-113). Following the 1989 legislation, the state-owned Central Electricity Generation Board (CEGB) was vertically and horizontally unbundled, which led to the creation of three generation companies, a combination of a national grid and pumped storage company, and 12 separate distribution companies. With the exception of one of the generation companies, Nuclear Electric, all assets were subsequently sold to the public by 1995 (Newbery 2006:112; Sotkiewicz 2006:6). One year later, the more modern plants within the nuclear fleet were sold (the balance of the stations remained in public hands until they were decommissioned). With unbundling and privatization, competition was also introduced and all generators (both private and public), starting in 1990, were mandated to sell their electricity in the Electricity Pool, with customers of greater than 1 MW able to buy in the wholesale market (International Energy Agency 2001:29; Newbery 2001b:1; Newbery 2006:112). Retail competition was extended to customers with consumption of greater than 100kW in 1994, and by 1999 all customers were free to switch—with about one half reportedly doing so (Sotkiewicz 2006:7) Among the

¹⁹ It is important to note that although Argentina was initially hailed as an exemplary reform model due primarily to its success in attracting new investment for generation, the country was hit hard by macroeconomic shock (in 2001-2), as documented by Woodhouse (2006a:135,139). The shock prompted the government to, among other things, change the denomination of IPP contracts from dollars to pesos, which in turn prompted a huge exit by foreign investors (Woodhouse 2006a:135,143).

noteworthy aspects in the England and Wales reform, particularly in contrast to that in the USA and Chile, is the speed with which assets were unbundled and privatized and with which competition was introduced. Equally noteworthy is the fact that the Electricity Pool, established in 1990, was replaced approximately a decade later, in March 2001, by the New Electricity Trading Arrangements (NETA), characterized by bilateral wholesale contracts (Newbery 2006:127).²⁰

2.3.4 Norway

Although the last among the early reformers profiled here, Norway was actually among the first to set up a spot market in 1971 to enhance the management of numerous large hydroelectric generators. In this market, generators who were low on water could purchase electricity instead of running down their reservoirs (Newbery 2001a:246). This development did not involve any actual restructuring of the market, which would only happen twenty years later. In 1991, following the passage of the Energy Act of 1990, Norway commenced functional unbundling as well as introduced competition into generation and supply (Jamash 2002:38). A new spot and contract market was subsequently established, plus a parallel financial market, with various hedging instruments, which would eventually extend to encompass Denmark, Finland, Norway and Sweden and be termed the Nord Pool (Jamash 2002:39; Amundsen, Bergman et al. 2006:145). By 2003, full retail choice was available in Norway. Unlike the previous reformers mentioned, Norway is distinct in that it did not make privatization a cornerstone of its reform, although there is some private ownership of assets (Jamash 2002:39; Sotkiewicz 2006:12).

2.3.5 Key take-aways

Although ideology played a significant role, particularly in the UK and Chile, and there was no set blueprint, the early reformers and reforms generally sought to improve efficiency across the ESI, primarily by introducing competition, and moving away from government involvement and toward what was perceived to be a more efficient private sector model of business.²¹ The text immediately below, excerpted from one of the countries' accountability offices, would therefore largely apply to all.

...the federal government has pursued a policy to restructure the electricity industry with the goal of increasing competition in wholesale markets and thereby increasing benefits to consumers, including lower electricity prices and access to a wider array of retail

²⁰ NETA was subsequently replaced by the British Electricity Trading & Transmission Arrangements (BETTA) in 2005, which extended the trading regime beyond England and Wales to include Scotland (Newbery 2006, pp.109, 141).

²¹ See footnote 16.

services. In particular, federal restructuring has changed how electricity is priced—shifting from prices set by regulators to prices determined by markets; how electricity is supplied—including the addition of new entities that sell electricity; the role of electricity demand—through programs that allow consumers to participate in markets; and how the electricity industry is overseen—in order to ensure consumer protection (United States Government Accountability Office 2005:2).

Although a comprehensive review of power sector reform outcomes will not be undertaken by this thesis, several points are worth noting in conclusion to this section. First, these first reforms were largely deemed to be positive (Hunt 2002; Besant-Jones 2006:121-125; Newbery 2006:29).²² Second, these reforms gradually crystallized into a standard model for power sector reform, which would be related to countries across the globe, as will be treated in-depth below. It is worth, however, briefly noting some of the linkages at this point. A number of the consultants involved in the reforms in Chile, Argentina and the UK, subsequently were involved as advisors to DFIs and developing country governments, and were often directly involved in the design of power sector reform in developing countries.

For example, among the many consulting groups to advise Tanzania on its power sector reform path, was one established in Buenos Aires in 1993 (Mercados 2007).²³ London Economics, which was instrumental through, among other things, its report, *The Case for Twelve*, in providing advice on steps for UK privatization, also provided policy advice to several countries including Kenya and Mozambique (London Economics 1993; London Economics 1997; London Economics 2007). London Economics has collaborated with the World Bank in providing general arguments for power sector reform following the UK model as well as provided such advice across a wide array of fora (Bates and London Economics (Consultants) 1997; Webb 1998). National Economic Research Associates (NERA) also played an active role in the UK's reform, along with London Economics, and subsequently went on to share its expertise with several developing countries, including extensive work in India (NERA Economic Consulting 2007a) (NERA Economic Consulting 2007b). Oxera, yet another UK-based consultancy, has played an active role in advising the UK's Department of Trade and Industry, which oversees electricity (Oxera 2007). Oxera has also since engaged actively in providing training to World Bank staff as well as working throughout Latin America and Africa on reform programmes.

²² It should be noted that successful outcomes have been challenged by among others, Sharon Beder, in *Power Play*, who accredits the reduction in tariffs to reduced fuel costs and describes how only a select few have gained from power sector reform (2003:205, 275, 337).

²³ Millan (2007) treats, among other issues, this dimension of international influences and consultants as it relates to the unfolding of power sector reform, including in his discussion of how reforms took place in El Salvador (Chapter 5).

Thirdly, although not taken up in detail in this thesis, reforms were ongoing in many of the early reforming countries. In some instances, second and third waves of reforms have been initiated to address issues overlooked in the initial reform programmes, including policies to ensure social and environmental sustainability as well as more significant competition (Inter-American Development Bank 2000:6). Finally, although not always the loudest voice in the room, caution was urged in carrying out what was largely unprecedented work, a point which will be returned to later (in section 2.4.4) (Joskow and Schmalensee 1983:93).

2.4 Powering ahead: subsequent reforms and reformers

In many industrialized countries, as discussed above, reforms were initiated to improve economic efficiency, particularly with regard to the price of power, that is, a lowering of tariffs (Bacon 1995b:138; Victor and Heller 2007:262). In contrast, in many developing countries, reforms were sought to address poor financial management and technical delivery, which were compromising efficiency. This in turn often meant raising tariffs to revenue-sufficient levels. Reform efforts were also targeted at introducing a space for private participation as the public sector was no longer able to provide the requisite funds for system expansion (Jamash 2002:1-2). Although the challenges faced by countries were different, it was generally believed that the introduction of private sector participation and market competition was the means to achieve improvements in the ESIs (O'Neill, Helman et al. 2006:479). This section gives a brief overview of conditions at the inception of reforms in developing country ESIs, followed by a discussion of the standard model, which was formulated as the primary way to achieve improved efficiency.

2.4.1 Pre-reforms: a snapshot of developing region ESIs

By the late 1980s, poor technical and financial performance were the defining features of many ESIs across developing regions. Among the indicators of poor technical performance was the fact that transmission and distribution (T&D) energy losses averaged about 20 per cent, against a world average of approximately 9 per cent for the same period (World Bank 2006c). South Asia registered the highest T&D losses, with Bangladesh, as one example, recording 35 per cent. These significant T&D losses (estimated to be 300 billion kilowatt hours (kWh) per year) translated into about US\$30 billion in losses through increased supply costs (World Bank 1993a:22-23).²⁴ Blackouts were frequent, with the Philippines representing 750 system blackout hours per year (hrs/yr), against a security standard of 7 hrs/yr. Load factors of above 70 per cent were the aim, but closer to 50 per cent in reality (Adamantiades, Besant-Jones et al. 1995:2).

²⁴ It is estimated that infrastructure industries (including water, railroads, roads, and electricity) across developing countries incurred a total of US\$180 billion in losses in the early 1990s due to technical inefficiency and mispricing (World Bank World Development Report 1994 cited in Kessides 2004: 3).

Poor financial performance was reflected by low debt-coverage ratios as well as insufficient cash for new investments. A survey of 60 developing countries in the late 1980s recorded that the utilities generated funds sufficient to cover only 12 per cent of their investment requirements.²⁵ Other cause for alarm was the average rate of return in many developing country utilities, which fell from about 9 per cent in 1973 to less than 5 per cent by the end of the 1980s, well below the cost of capital (World Bank 1993a:20). Further impeding productivity and impacting financial performance was the number of utility customers per employee. Among the worst performers in this regard was Rwanda with only 6 customers per employee and Burundi at 9 (World Bank 1993a:20).

A further performance measure, which deserves mention in this context, were the low electricity access rates of approximately 46 per cent across developing regions in 1990, with only 16 per cent of the population in Sub-Saharan African with access to electricity (by 1990) (International Energy Agency 2002:20). Approximately 80 per cent of those without access lived (and still do) in rural areas (International Energy Agency 2002:17). These low access rates contributed to low per capita consumption. Per capita consumption rates of low income countries amounted to just 279 kWh or just 13 per cent of the world average of 2134 kWh per person (with considerable variation recorded across regions, including an average of 51 kWh per person in Sub-Saharan Africa and 1225 in Latin America and the Caribbean) (World Bank 2007b).²⁶

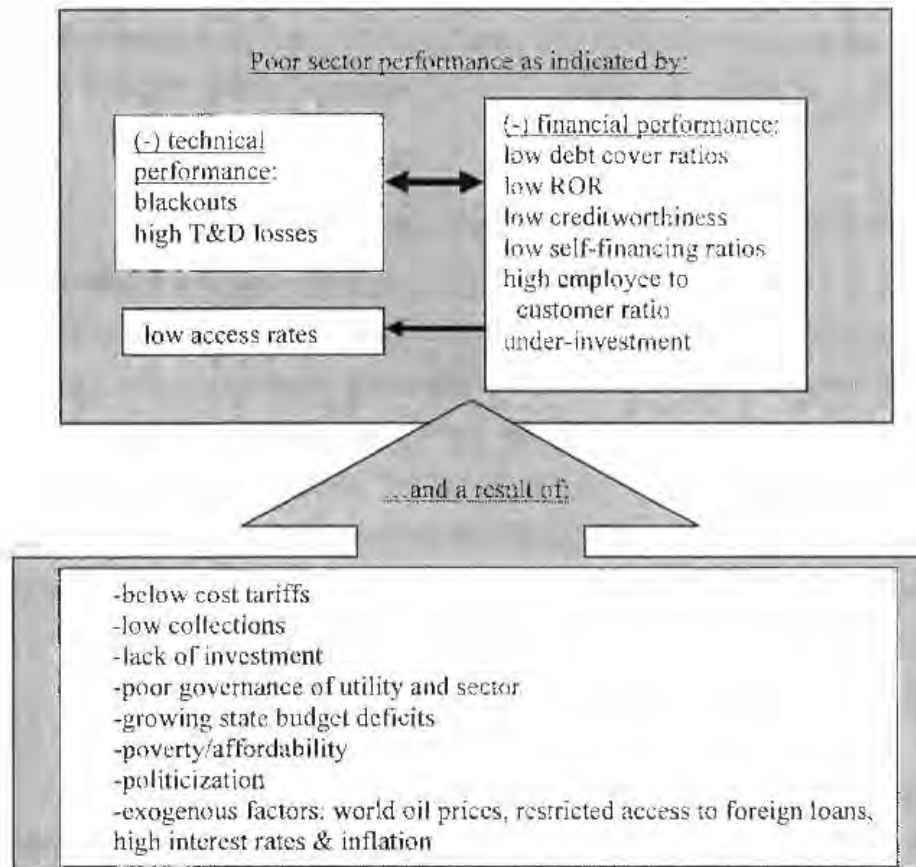
Among the most immediate causes of the technical and financial deterioration was increasingly below cost tariffs, with tariffs in 1988 across a sample of developing countries amounting to 3.8 US cents per kWh, equivalent to about half of the average tariff in Organization for Economic Cooperation and Development (OECD) countries (World Bank 1993a:25-26). Another more revealing measure of tariffs was that in 1992, it was estimated that total government subsidies for energy in developing countries were over US\$50 billion, which was greater than the total official development assistance that these countries received that year (Goldemberg and Johansson 1995:7). Below cost tariffs meant that the utility itself was not able to finance technical improvements, through its own resources, let alone consider expansion of the grid. The poor financial indicators further prevented many utilities from accessing the capital markets given their perceived lack of creditworthiness (World Bank 1993a:27).

²⁵ In 1990, it was estimated that capital expenditure for power expansion programmes for developing countries in the 1990s would amount to approximately US\$1 trillion (in 1989 US dollar terms), (Moore and Smith 1990:i, 12), as will be discussed in greater detail in section 2.6.

²⁶ This regional data dates to 1992 (not 1990) in contrast to the other information presented in this paragraph as 1992 is the earliest year kWh per capita is available across regions.

What had caused tariffs to decline to this level, and what were the other factors influencing such poor technical and financial performance? Figure 2.1 offers a description of the poor performance and related causes.

Figure 2.1: Poor sector performance: indicators and causes



Source: based on author's compilation including: Jhirad (1990:365-375); Moore and Smith 1990; World Bank 1993a:19-33; Kessides 2004:3; Besant-Jones 2006:10; Victor and Heller 2007:257.

A couple of points are worth noting. First, there was an interplay between poor technical and financial performance; that is, technical performance was impacted by poor financial performance and vice versa. Secondly, there is some overlap in terms of the different factors and symptoms mentioned. For instance, 'low self-financing ratios', which is included as one of the signs of poor financial performance in the Figure above, contributed to the 'lack of investment', which had a direct impact on both poor technical and financial performance (World Bank 1993a:19, 21-23). Thirdly, budgetary constraints at the national level together with a host of exogenous factors had a significant influence on overall poor performance as well (World Bank 1993a:19). In sum, although poor performance prompted power sector reform, the causes of such performance were multifold and deep, which helps to explain the mixed outcomes of power sector reform (treated in section 2.5.2).

An important point is that the conditions predominating in most developing countries' ESIs at the inception of power sector reform, as described above, were dramatically different from the conditions known in most of the early reforming countries (USA, Chile, UK and Norway). In the latter, there was generally significant excess capacity (Newbery 2001b:4), electricity access was nearly universal, and utilities did not face the same financial constraints. The drive in most industrialized states, as noted previously, was for economic efficiency, with the institutional foundations largely in place to help facilitate reform (Williams and Ghanadan 2006:820).

2.4.2 Antidote for poor performance: evolving power sector reform

Despite the stark contrast in conditions, the experiences of the early reformers became the reference point for countries across the developing world. Stated in somewhat different terms, Bacon and Besant-Jones describe how, "the pioneering reforms to power sectors in Chile, England and Wales and Norway, during the 1980s...have motivated numerous industrialized and developing countries to follow them in the 1990s" (Bacon and Besant-Jones 2002:6). The ways and means of "motivating" were multi-fold and included both domestic and international initiatives and initiators, including the World Bank, which will be treated in this section.

Informed by recent reforms in the USA, Chile, England and Wales and Norway, and with clear indicators that developing country ESIs were performing sub-optimally, in 1993, the World Bank issued "The World Bank's Role in the Electric Power Sector: Policies for Effective Institutional, Regulatory and Financial Reform". The overarching argument was not for outright privatization of assets and competition, but rather improving performance through commercialization, corporatization, and enhanced regulation. Private participation was highlighted as a means to improve sector performance and help meet the investment gap (World Bank 1993a:12-18).²⁷

The electricity sector had historically been a main target of World Bank lending, with an estimated cumulative US\$75 billion (in 1990 prices) or about 15 per cent of the Bank's total lending (from 1947 through 1991). It was estimated that in the 1980s, the World Bank accounted for approximately 7 per cent of total power investments in developing countries, not including co-financing that the Bank helped raise (World Bank 1993a:34). Thus, within the World Bank, electricity was recognized as a priority sector, and, in terms of total investment flows, the Bank's contribution was substantial, which made the 1993 electricity policies of particular significance. The document, which is considered among the earliest articulations of

²⁷ Although the International Monetary Fund (IMF) may have also been influential in advancing the reform agenda, the IMF, unlike the World Bank, never developed sector specific policies and reform recommendations, and therefore discussion of the institution's role remains limited in this thesis.

the new power sector reform for developing countries, laid out the World Bank's role and a general set of recommendations, grouped under five principles (World Bank 1993a:59-77).

- *Transparent regulatory processes*, which included a clear legal framework as well as the enforcement of rules and (clear and transparent) means for amending such rules, were generally recommended and made a prerequisite for any power sector lending on behalf of the World Bank. Market pricing and demand-side management were also enumerated in this context as goals for the sector.
- For the least developed countries *importation of services* were recommended, which would address the issue of insufficient human resources available to spearhead and manage (early) reforms.
- It was imperative that *commercialization and corporatization* be adopted (by which it was meant that the entities within the ESI must operate as commercial enterprises, with government/state participation "more transparent") together with *private sector participation*.
- *Commitment lending* was an explicit statement that the World Bank would only lend to countries with a clear commitment to improving their ESIs, following the principles laid out.
- The World Bank would encourage *private investment* through a number of initiatives including lending to national financial intermediaries and providing investment guarantees.

These policies would inform World Bank lending practices throughout the 1990s, which will be explored in further depth in sections 2.4.4 and 2.5.1 as well as throughout Chapters four through seven. Evidence may also be found amidst other DFIs such as the Asian Development Bank (ADB), the Inter-American Development Bank (IADB), and the UK Department for International Development (DFID) (DFID 2002).^{28 29} To take two such examples (ADB and IADB), in 1995, articulating its policy recommendations for the energy sector, the ADB identified as a first priority: private sector participation as pivotal in funding major energy projects. Thereafter the multilateral finance institution listed the importance of energy

²⁸ It should be noted that the World Bank did not withdraw from funding power infrastructure exclusively. Rather throughout the 1990s, there was a sharp reduction particularly in thermal power production investments, with some notable exceptions including two plants in Kenya (to be described in Chapter 5). Funds were concentrated in providing technical assistance to assist in investments by the private sector and in transmission and distribution projects, which as described in section 2.2, represented the natural monopoly components of the system.

²⁹ There appears to be no substantial evidence for United Nations Development Programme (UNDP) articulating and implementing the standard prescription related to power sector reforms. Instead, the UNDP appears to have focused its efforts on rural energy and diversification of generation to include renewable energy (UNDP per com 2007).

efficiency and more extensive integration of environmental concerns into energy sector development. In sum, however, “The overall thrust of the suggested policy initiatives is to encourage the [developing member countries] to develop appropriate market structures and to encourage greater competition in the energy sector” (Asian Development Bank 1995:30).

In terms of the IADB, the organization’s 1996 Public Utilities Sectoral Operational Policies (under which electricity was included) outlined five objectives, namely, ensuring long-term sustainability of service; achieving economic efficiency; safeguarding quality; promoting accessibility; and meeting wider national objectives (Inter-American Development Bank 1996). In the new spirit of commercialization, the IADB indicated that:

A number of important trade-offs exist among the objectives mentioned before....however, there is one area in which no compromise should be made and that is, in meeting the objective of long-term service sustainability by ensuring that financial flows rise to a level compatible with full cost recovery, while guaranteeing economic efficiency as a general goal of service provision, (Inter-American Development Bank 1996).

The means to achieving such objectives, as spelled out by the IADB, were multi-fold, with significant emphasis given to competition throughout each of the steps (Inter-American Development Bank 1996). Privatization and private participation, although alluded to, were not laid down as policy, however, at approximately the same time, the IADB did encourage extensive private sector participation, including via a “private sector window” for privately-financed projects, including in infrastructure, that required no sovereign guarantee, as a means to facilitate private sector flows (Inter-American Development Bank 2006:3) (Inter-American Development Bank 1996).

It should be reiterated, however, that influences were not merely external, and to quote one individual who played roles in both international and domestic organizations (in Latin America) at varying points of his career, “The [development] [b]anks didn’t impose the reform but promoted it” (Millan J. per com 2007). In other words, DFIs were at the forefront of reform, but they were not alone. Domestic actors and international policy consultants had a role to play as well in shaping and ultimately carrying out reform policy, as will be sketched in sections 2.4.4 and 2.5.1.³⁰

³⁰ This assertion stands in contrast to some of the critics of power sector reform who charge that it was a top-down effort driven by multilateral finance institutions, “To facilitate the transition, donors and multilateral agencies provide not only reform-targeted loans but blueprints for the process as well. These agencies have been architects of the reforms, with many countries obliged to take on technical assistance as part of the loan package,” (Wamukonya 2003:1274). See also Williams and Ghanadan (2006:818).

2.4.3 Advent of a new standard model

Over the course of the decade, as power sector reform was being enacted throughout developing regions and ongoing in several industrialized countries, a series of key steps came to be identified. These steps are loosely connected to the 1993 electricity policies of the World Bank but go much further in setting out a course of action for full liberalization of power markets. By 1999, these reform steps had been formulated roughly as follows:³¹

1. *Corporatization*: involves the utility being transformed into a separate legal entity (separate from the ministry/government), with all associated rights and obligations including governance structures, managing budgets, borrowing, procurement, labour employment, payment of taxes and dividends.
2. *Commercialization*: represents a move toward cost-recovery in pricing, improvements in metering, billing and collections and could involve adopting internationally recognized accounting practices as well accounting for all subsidies.
3. *Passage of the requisite energy legislation*: provides a legal mandate for restructuring, as well as the legal framework to allow private/foreign participation/ownership in the sector.
4. *Establishment of an (independent) regulator*: aims to introduce efficiency, transparency and fairness in the management of the sector, specifically to prevent anticompetitive activity, encourage appropriate investment and protect consumers.
5. *IPPs*: introduce new (private) investment in generation, with long-term PPAs.
6. *Restructuring*: involves unbundling the incumbent (state-owned) utility, which may take the form of vertical and/or horizontal unbundling of generation, transmission and distribution assets as preparation for privatization of (profitable) assets and the introduction of competition.
7. *Divestiture of generation assets*: divests state-ownership in part or full of generation assets to private sector.
8. *Divestiture of distribution assets*: divests state-ownership in part or full of distribution assets to private sector.

³¹ Reform steps have been identified in Bacon (1999:4), but have been embellished with definitions found in Adamantiades (1995:6-7), Besant-Jones (2006:11), Williams and Ghanadan (2006:822). Commercialization was not included as a separate step in Bacon's 1999 report, as has been noted above, however, in earlier work (Bacon 1995:131) the author clearly indicates: "an almost inevitable first step is to turn the state enterprise into a corporation and then submit this corporation to commercial discipline." Thus, commercialization was considered an extension of corporation. Also not identified in Bacon (1999) was 'competition', step 7, due to the fact that steps were largely based on what the author observed as being carried out in developing countries in 1998 (Bacon R. per com 2007a). "Basically at the time of research (1998) even the possibility of private entry was largely new. Competition would have been effectively meaningless with only a very few cases for those countries which had done some reform" (Bacon R. per com 2007b).

9. *Competition*: introduction of wholesale and retail markets.

These milestones taken together have been referred to as the “standard prescription” (Hunt 2002:8, 239) or the “standard model” (Littlechild 2006:xviii), which draws on a “textbook architecture” (Joskow 2006:4,8; Littlechild 2006:xviii). In terms of the sequencing of the steps, by 1999, it was posited that:

There is a logical sequence to reform steps if a country is working toward full private sector participation and competition, and the survey results were expected to show this pattern. First the state company must be corporatized and commercialized. Next a law permitting private entry must be passed. Then regulation must be implemented. After that the state enterprise should be restructured through vertical and horizontal separation. Private Greenfield investment could then be allowed. Finally, the existing assets should be privatized (Bacon 1999:3).

Minor variations of the standard model have been laid out, with considerably greater emphasis placed on the creation of competitive wholesale and retail markets (linked to steps 6 and 9 above), for more developed ESIs. The following additional elements have been laid out as the textbook architecture for the creation of full competition (Hunt 2002:8):

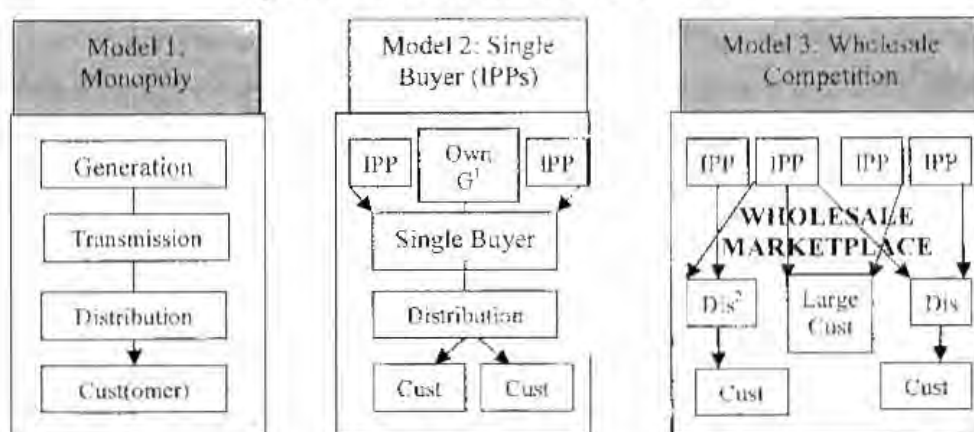
1. *Demand Side*: Hourly metering for most of the consumption and pricing plans that expose customers to the spot price for some of their consumption.
2. *Trading Arrangements*: System operations separated from traders and regionally consolidated. Trading arrangements based on an integrated model, with central dispatch and locational energy prices.
3. *Transmission business model*: Control of transmission separate from traders; pricing and expansion arrangements; [the] preference is for regional profit-making regulated transmission companies (transcos) incorporating the system operator.³²
4. *Supply side*: Remove barriers to entry. Buy out of the old regime by valuing assets. Expand market power control, divest utility generation into smaller parcels.
5. *Retail access*: When production markets are working, choice for all customers, [which requires] extensive settlement mechanism and customer education, and decisions about default provision.

³² Although outlined in Hunt (2002:8), it should be noted that a transmission model has not been widely prescribed; instead, the transmission sector has been marked by the diversity of different models embraced during reform.

Joskow's latest and more succinct version of the "textbook model" is: privatization of state-owned enterprises; vertical and horizontal restructuring to facilitate competition and mitigate self-dealing and cross-subsidization problems; performance based regulation applied to the regulated transmission and distribution segments; good wholesale market designs that facilitate efficient competition among existing generators; competitive entry of new generators, and retail competition, at least for industrial customers (2006:8). Victor and Heller refer to the "standard textbook model", which roughly corresponds to these steps (2007:6) and is simply stated as: unbundle; privatize; create regulatory institutions; and create markets. Besant-Jones (2006:11) provides his version, identifying it as "elements of full-scale market reform" not a prescription per se, with the major addition, which is also stated in Bacon and Besant-Jones, (2002:4), of "focusing government's role on policy formation and execution." Dubash in *Power Politics* refers to "a complex new model for the electricity sector" (2002:12) and details some but not all of the steps listed in the text above. Other references include Williams and Ghanadan's "standard menu for reform" (2006:821), which is largely based on Bacon's steps, but again with the addition of competition as a final, separate step.³³

These steps have been associated with four different industry models that illustrate the degree of competition for and in the market (Joskow and Schmalensee 1983:93-105; Adamantiades, Besant-Jones et al. 1995:9; Hunt 2002:42-54; Kessides 2004:144,148,150). The first model (below) depicts the vertically integrated monopoly structure, which characterized most ESIs at the inception of power sector reforms.

Figure 2.2: Standard model: models 1-3

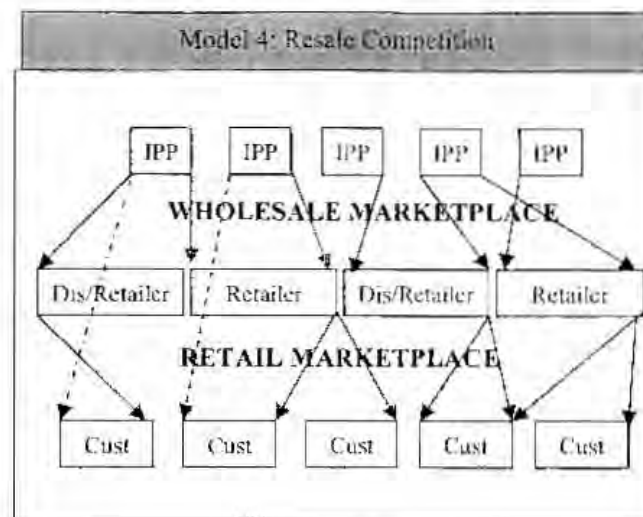


Source: Hunt (2002:42-45)

Notes: ¹"Own G" refers to state-owned generation. ²"Dis" refers to distribution company. Hunt provides two different variations of Model 1 and Model 2, not depicted here, which include (in Model 1) a distinct distribution company and (in Model 2) many distinct distribution companies (2002:42-44).

³³ There is an important distinction among the authors cited here and above--with Joskow, Hunt and Littlechild providing a normative framework and Victor and Heller, Dubash, and Williams and Ghanadan providing a descriptive framework. Bacon and Besant-Jones' work appears to be partially descriptive and partially normative.

Figure 2.3: Standard model: model 4



Source: Hunt (2002:54)

Notes: "Dis/Retailer" refers to distribution company and/or retailer; "Cust" refers to customer, as noted above.

Three points should be made in concluding. First, four of the nine reform steps laid out above, namely corporatization, commercialization, passage of an energy law, and establishment of an independent regulator, may all take place under the first model (monopoly) to enhance performance. These preliminary steps are what are required to transform the ESI from a government agency or department into a commercial enterprise (Hunt S. per com 2007). Secondly, the extended standard model for competition, detailed above as five steps, is applicable to models 3 and 4 (Hunt S. per com 2007), namely wholesale and retail competition, and presupposes the completion of the earlier steps outlined in Bacon (1999). Finally, to implement these five steps and achieve either wholesale or retail competition (models 3 or 4), sophisticated legal and financial infrastructure is required (Hunt S. per com 2007)³⁴—the absence of which, as alluded to previously, is one of the main characteristics of many less developed countries. Thus, although the model described above, emerged as a standard, it is arguable that almost half of the steps were not necessarily relevant to the conditions on the ground in most developing countries on which it was brought to bear.

2.4.4 Exceptions to the standard model and the role of the World Bank

The previous section concluded by advancing the idea that there were clear prerequisites to introducing wholesale and retail competition, also known as the culmination of the standard model. Commercialization, corporatization, and unbundling were among such prerequisites. In

³⁴ In its Sectoral Operational Policies for Public Utilities, as previously referenced, the Inter-American Development Bank, indicated that, "the existence of competition in the market, and some kinds of private sector participation can only function effectively within a specific legal context, countries should carefully study the adequacy and compatibility of the proposed options with their legal systems," (Inter-American Development Bank 1996:4).

addition to this emphasis on proper sequencing, a series of exceptions to the reform model have been raised since the inception of power sector reforms in developing countries.³⁵ This section does not purport to be an exhaustive inventory of references to exceptions, but rather to showcase approximately 10 examples, in roughly chronological order.³⁶ The section also revisits broad generalizations on how the World Bank formulated, advocated and advanced the standard model for power sector reform in its client countries.

Three years before the 1993 electricity sector policy document was issued, the World Bank's Industry and Energy Department, recommended through a discussion paper (not official Bank policy) that what was needed was not wholesale competition, which was deemed irrelevant to most least developing countries (World Bank 1990:81).

Competition at the wholesale level is a policy issue that does not rank high on the agenda for power sector reforms in LDCs. In most countries, the efficient structure and size of the power industry leaves little or no room for market forces to guide the use of generation capacity. Furthermore, the concept of wholesale competition in itself is a questionable approach since the market forces it intends to stimulate may merely replicate the existing industry structure on the basis of contracts, (World Bank 1990:81).

Instead what was advanced was 're-regulation' to ensure that utilities, whether privately or publicly owned, had both sufficient oversight and autonomy to improve performance (World Bank 1990:vi, 82).

Although by 1993 ideas had advanced as previously described in the World Bank's 1993 electricity sector policy, the policy document makes explicit that: it should serve as guiding principles; consideration should be given to the variation in country situations, and specific actions must be worked out at the country level (World Bank 1993a:13), i.e. a one-sized approach would not work for all.

In 1995, Bacon, (1995a) in another World Bank discussion paper, challenged policy makers to reconsider whether horizontal and/or vertical unbundling was appropriate to small systems. According to Bacon, "the most prominent case (England and Wales) is operated on a scale completely different from that in many countries for which it is being referred to as a model" (Bacon 1995a:4). With high costs associated with many of the steps related to unbundling and the introduction of competition, caution was urged, along with detailed economic analyses to ensure that benefits outweighed costs. Before the reform model is implemented, decision makers should be able to answer a series of questions including the

³⁵ Recall as well that caution was urged (Joskow and Schmalensee 1983:93), as previously referenced, for all reformers.

³⁶ All references appear in chronological order with the one exception of Joskow 2006, which is cited before the World Bank 2004 due to the logic of the material.

extent to which unbundling of small systems will impact on employee efficiency, as career advancements may be stunted in a newly organized, smaller, firm (Bacon 1995a:19,33).

Hunt and Shuttleworth (1996) provided such exceptions and Hunt (2002:27) reiterated them again in *Making Competition Work in Electricity* when she indicated that small countries, or those with low demand and/or inadequate transmission networks were considered possible candidates for continued monopolies.

Alternatives to wholesale and retail competition were expounded on in Jamasb (2002:43-47), who described how countries with smaller systems should aim for competition for the market, rather than in the market, through: the single buyer model, bilateral contracts (PPAs), and management contracts.³⁷

Although a strong proponent of the prescription, Joskow (2006:8) acknowledges that there may be some regulated vertically integrated monopolies that may perform well and for which “comprehensive reforms reflected in the textbook model might have little positive effect on performance.”

In 2004, the World Bank’s “Operational Guidance for World Bank Group Staff: Public and Private Sector Roles in the Supply of Electricity Services,” again raised the exception of small systems, which may, as indicated by Hunt, be more efficient as monopolies (World Bank 2004a:7-8). However, this document, which will be discussed further below, represented the first major World Bank policy document since the 1993 electricity sector policy, also went much further than simply referencing an exception. Rather, the document was premised on the need to rethink the approach to power sector reform, which included: integrating stronger poverty, affordability and environmental elements; treating all reform steps as means to enhanced performance and poverty reduction, not ends in themselves; and that many of the Bank’s client countries actually fall into the category of being too small to support competition (World Bank 2004a:2-3,7).

These points were reinforced by Besant-Jones, in his 2006 treatise, published by the World Bank, which was intended to complement the 2004 Operational Guidance note, cited above, and provide relevant and detailed applications of the policy advice to World Bank staffers as well as all those involved in making critical decisions related to ESI reform. Almost two decades since the first cautionary note was issued, Besant-Jones writes, “The case for unbundling gets weaker the smaller the system, the more undeveloped the institutional capacity, and/or the weaker the general country conditions” (Besant-Jones 2006:61).

In summary, attention to important exceptions to the standard model have been raised throughout, however, there has often been a misunderstanding of the extent to which the World

³⁷ The Inter-American Development Bank in its 1996 Sectoral Operational Policies for Public Utilities also included warnings to consider market size and shape as well as the fact that such size and shape may preclude unbundling (Inter-American Development Bank 1996:2).

Bank, among the most significant development agencies in Africa,³⁸ formulated, implemented and advocated what has come to be known as the standard prescription, as detailed by Bacon in general terms and Hunt and Joskow, among others, specifically with regard to creating competitive wholesale and retail markets.

The World Bank did advance power sector reform through its 1993 policy, but never advocated outright liberalization (in any policy documents) as per many of the critics (Wamukonya 2003:1274; Williams and Ghanadan 2006:821; Yi-chong 2006:804). Caution about application was noted since the inception of the first reforms, recommending tailor-made solutions (World Bank 1993b:6). Such caution would be reiterated by specific World Bank staff over the decade. Although numerous technical papers were published, no formal policy guidance was provided between 1993 and 2004 when the World Bank issued its “Operational Guidance for World Bank Staff” (2004a).³⁹ The oft-cited Bacon Scorecard was not intended to be prescriptive, but rather in the words of the author “was essentially designed to allow simple yes /no answers for the maximum number of countries and what we thought at that time were key reform steps” (Bacon R. per com 2007a).

Nevertheless, certain World Bank staff as well as World Bank consultants appear to have advocated and ultimately implemented liberalization in power sector reform. But to reiterate, this was not spelled out in any policy document (World Bank per com 2007a). There is also evidence of the enthusiasm for the model being home grown, as seen for example in the case of Tanzania’s Parastatal Sector Reform Commission (PSRC), treated in greater detail below (section 2.5.1), which while funded in part by donor agencies, also had significant local input and influence which rallied around the standard prescription. Furthermore, as previously discussed (section 2.3.5), numerous consultants working independently of the World Bank were also involved in spreading the standard model.

The role of this thesis is not to be an apologist for the World Bank. After all, the Bank’s role was pivotal in shaping power sector reform. For instance, in one of the more self-critical texts published by the World Bank’s Operations Evaluation Department in 2003, it is written:

³⁸ In 2004, 2005 and 2006, net financial flows from IDA, the concessionary loan window of the World Bank, to Sub-Saharan Africa totalled approximately US\$2.5 billion, which was greater than any other development agency and, in terms of IDA, greater than to any other developing region. (World Bank 2005a:360) (World Bank 2004b, p.344; World Bank 2006a: 358)

³⁹ In *Power for Development*, the authors urge the World Bank Group to provide operational guidance to staff on how to promote private sector development in the electricity sector, given increased macroeconomic and political risk and limited private sector interest, and further recommend that such guidance should clearly emphasize how to deal specifically with poverty reduction and environmental aspects together with technical and financial performance improvements (Manibog, Dominguez et al. 2003:57). The response was two-fold, first the 2004 *Operational Guidance for World Bank Staff* (World Bank 2004a) and subsequently *Reforming Markets in Developing Countries: What We Have Learned* (Besant-Jones 2006).

The Bank's approach to sector reform, as it evolved in the 1990s, went beyond what was mandated by the 1993 Electric Power Lending Policy. The policy promoted commercialization and corporatization before privatization, as a means to introduce competition and innovation. It was based mainly on the reforms in Chile, England, and Wales, which were the only experiences available at that time. Most power sectors of Bank client countries, however, showed little prospect for reaching commercial standards because of the inefficiencies from state ownership and poor governance. Subsequent to the 1993 policy, *and without enunciating it as a major strategic change, the Bank thus mostly advocated privatization* (as well as private participation through management contracts) as a means to achieving commercialization (Manibog, Dominguez et al. 2003:50) (italics added by author).

The text clearly spells out how the Bank advanced privatization as a first step where commercialization was not initially achievable, however, as previously indicated, not only was this unwritten practice not official policy, it was practiced by some and not all. This disconnect between policy and implementation may explain why for instance many of the stakeholders in Kenya, Egypt and Tanzania have indicated (as will be detailed in Chapters four through six) that the World Bank was requiring competitive markets. The argument here is there appears to have been one official policy and one less official policy that was advanced on the ground. While this has been acknowledged in some reports, including (Besant-Jones 2006:31; Williams and Ghanadan 2006:821), it has not been emphasized to date and not been clearly documented.

2.5 An unexpected ending to the story

Despite the difference in starting conditions, and despite the exceptions noted, power sector reform and the standard model, shaped largely in industrialized countries, were applied to developing countries. To return once again to the example of IPPs, Woodhouse provides the following observation, "While a body of theoretical and empirical work guided the architects of these early private participation in infrastructure (PPI) schemes, careful planning often faded to the background during the IPP boom years. In this environment, actual practice drifted from the theoretical foundations for PPI...particularly once the pioneers had blazed a trail that was easier for others to follow" (2006a:134). And so it happened that Tanzania, to consider one example, became a candidate for wholesale competition, with installed capacity of approximately 900 MW, a largely hydro-dominant system (at the time that plans for power sector reform were being developed), and a state utility that was far from following commercial practices. The next section commences by briefly reviewing one country example (Tanzania) to illustrate how power sector reform and the standard model were enacted. Subsequently, an overview of reform paths across developing countries is presented. What this section

deliberately does not undertake is a review of the literature assessing outcomes of power sector reform, including performance measurements, due to the controversial nature of such literature, which is partly the result of insufficient quantitative data mapping actual outcomes (as acknowledged most recently in Besant-Jones (2006:31)).^{40 41}

2.5.1 An illustration: Tanzania

Still on the books, but not yet implemented, in Tanzania, is a plan to unbundle TANESCO, the state-owned utility, into separate generation, transmission and distribution companies, privatize assets and introduce competitive markets into the ESI (Mercados 2007; Mercados per com 2007; Parastatal Sector Reform Commission per com 2007; EWURA per com 2007a). The plan was developed by Mercados, a consultancy, as previously noted (in section 2.3.2), founded in 1993 in Buenos Aires, Argentina, a country which established wholesale competition starting in 1992 (Dyner, Arango et al. 2006:604).

PSRC, a government agency established in 1992 to privatize government-owned enterprises in order to increase efficiency and enhance performance, commissioned Mercados, as well as a number of other consultants (including Stone & Webster), to design a series of plans to advance power sector reform in Tanzania. The World Bank and DFID, the primary DFIs, which fund the PSRC, may also be linked to the advancement of power sector reform.

The challenge of assigning responsibility for the nature of the reform plans increases not only with the myriad actors involved, but also due to the inter-linkages. For instance, the World Bank provided the funding for Mercados' consultancy work, through credit #Q073:3304, the Privatization and Private Sector Development Project. According to PSRC and Mercados, however, World Bank staff did not interfere with the consultancy work, which was carried out independently by Mercados, and which both (Mercados and PSRC) also contend was tailor-

⁴⁰ Among the more extensive econometric analyses, which reviewed panel data for 51 developing countries between 1985 and 2000, concludes that capacity utilization and hence technical performance improves with privatization (though not necessarily competition). There is no evidence for improvements in electricity penetration, capacity expansion and labour efficiency with privatization alone; improvements are observed only when privatization is coupled with either regulation or competition. The study provides no conclusive data on financial performance (Zhang, Parker et al. 2002:22-23). These conclusions were, however, reached before many developing countries had implemented reforms and/or were in the midst of reforms. Other shortcomings are described in Jamasb, who offers an extensive review of the literature on the determinants and performance of electricity reform in developing countries and concludes that no comprehensive series of measures exist that assess, monitor and compare reforms on a regular basis. Studies that have been carried out lack, among other things, adequate performance indicators, market structure variables, and comprehensive panel data (2005:46).

⁴¹ Kessides in reviewing the impact of reform across infrastructure industries makes the case that most empirical evidence points to positive results for privatization and restructuring, specifically the fact that privatization improves efficiency (as regards to labour and total factor productivity) as well as utilities' financial performance and causes service expansion. There is also a considerable body of evidence, he highlights, including Zhang noted above, that points to positive outcomes being contingent on post-reform/privatization regulation as well as the degree to which competition has been introduced (2004:53-54).

made to suit Tanzania's conditions, that is, not as the critics allege, a copy and paste job based on early experiences in Latin America (Mercados per com 2007; Parastatal Sector Reform Commission per com 2007). Still the World Bank did facilitate this exchange by underwriting it.

Furthermore, long before Mercados' plan was issued in 2004, power sector reform, following the model carried out by the early reformers had found its way into Tanzania's policy. "In October 1999, the government approved a [World Bank funded] power sector restructuring strategy, which recommends unbundling TANESCO vertically and horizontally into generation, transmission and distribution businesses with the objective of introducing private sector investors and operators...Implementation of the reform programme is being supported by the Privatization and Private Sector Development Project [which was also later used to fund the Mercados work above]..." (World Bank 2001:5). The World Bank thus played a critical role in funding this initiative, however, the project was also supported by a host of domestic actors (Tanzania Ministry of Energy and Minerals per com 2007; EWURA per com 2007a).⁴²

This inter-linkage of influences and ideas may be seen perhaps most clearly through the steps that led to the 1999 strategy document referenced above, also known as the Framework for the New Direction of the Power Sector. The Framework was drafted throughout 1998, by experts from the Ministry of Energy and Minerals (MEM), Ministry of Finance, Ministry of Planning, Ministry of Justice and Constitutional Affairs, TANESCO and PSRC. Subsequent to the drafting, the authors of this document went on a tour of three Latin American countries, namely Argentina, Bolivia and Jamaica, which had all carried out degrees of power sector reform, with Argentina the most advanced of the three in terms of implementing the standard model (Tanzania Ministry of Energy and Minerals per com 2007; World Bank per com 2007d).⁴³ This tour was funded by Sida and organized together with the World Bank (World Bank per com 2007d). Following the tour, the findings and lessons of the visit were internalized in the draft framework, which was then finalized through two workshops, arranged

⁴² Further evidence for both multilateral involvement in supporting power sector reform a la standard model may be noted in Tanzania's Interim Poverty Reduction Strategy Paper, issued in March 2000, which listed among other proposed completion conditions, the following: "initiate process for the unbundling of Tanzania Electric Supply Company Ltd.(TANESCO) into autonomous commercial entities" (Tanzanian Authorities 2000:3). As noted for the 1999 World Bank funded initiative, however, each initiative had its domestic champions/counterparts (EWURA per com 2007a).

⁴³ Tours of the following countries were also conducted: Uganda, Mozambique and Zambia to address issues associated with the formation of the institutional framework for the handling of rural electrification programmes; Zambia, South Africa, USA and Mozambique for lessons and experiences in arranging regional grid interconnections and electricity trading via the Pools, which were arranged after the drafting of the Power Sector Reform Framework; and India, Malaysia and Singapore to enable the Government to understand the pros and cons of implementing the recommendations which were put forward by the restructuring and trading consultants. Finally, a tour in Sweden was made during the time when the Ministry was drafting its Energy Policy of 2003 (Tanzania Ministry of Energy and Minerals per com 2007).

by the MEM in collaboration with PSRC, with input from the World Bank, International Monetary Fund (IMF), Swedish government, Japanese government, Spanish government, European Union, African Development Bank (AfDB) and European Investment Bank (EIB) (Tanzania Ministry of Energy and Minerals per com 2007).

Among stakeholders in Tanzania as well as international funders, there is disagreement about who is most responsible for advancing the standard model, with Mercados, the World Bank and PSRC, each singled out.⁴⁴ Also disputed is the applicability of the standard model, with PSRC and Mercados asserting that the creation of competitive markets is apt, but as per the consultants' recommendations, not right now, i.e. it will be appropriate in the long-term (Mercados per com 2007; Parastatal Sector Reform Commission per com 2007). Other policy makers in Tanzania and World Bank staff hold differing opinions, questioning the ultimate applicability given the country conditions (EWURA per com 2007a; World Bank per com 2007a). It is not the goal of this thesis to settle the dispute, but rather to showcase how the standard model evolved in the case of Tanzania. In closing, it is important to mention that however applicable or not the standard model may be to the Tanzania ESI, at this point, the only element of the model actually in place is an IPP programme, which will be evaluated in Chapter six.

2.5.2 Reform paths taken

The example of Tanzania highlighted above was intended to show how the standard model took root in the developing world. Although this thesis does not argue that such experience was uniform across developing countries, it is suggested that such experience is not altogether uncommon. This section provides a birds eye view of reforms actually carried out, with IPPs emerging as among the most significant pieces.

Results for power sector reform across developing countries were reported in a systematic way starting in 1999 in the oft-cited Scorecard, which found that from a total of 115 developing countries, about a third of the reform steps⁴⁵ had been carried out (Bacon 1999:1). By this time, only 12 countries had embarked on all steps of reform identified, and 42 had not yet embarked on any, with the most activity occurring within the Latin American and Caribbean region and the least occurring in Sub-Saharan Africa. Also noteworthy is that IPPs were second only to corporatization in terms of reform steps undertaken (Bacon 1999:4). This data was reproduced in Bacon, noted below, which also shows how the prevalence of IPPs exceeded the reform

⁴⁴ The Ministry of Energy and Minerals although involved throughout and although including champions of power sector reform is largely seen to have been less involved in advancing the standard model than PSRC, the World Bank and Mercados (EWURA per com 2007a; World Bank per com 2007d).

⁴⁵ These reform steps refer to: corporatization/commercialization, energy law, IPPs, regulation, restructuring/unbundling, generation assets divested, distribution assets divested, as discussed in section 2.4.3 above.

indicator for every region, unlike for any other reform step, including corporatization (Bacon and Besant-Jones 2002:8).

Table 2.1: Number of countries having taken key reform steps by region as of 1998

Region (No. Countries)						
Key Step	AFR (48)	EAP (9)	ECA (27)	LCC (18)	MNA (8)	SAR (5)
Corporatization	15 (31%)	4 (44%)	17 (63%)	11 (61%)	2 (25%)	2 (40%)
Law	7 (15%)	3 (33%)	11 (41%)	14 (78%)	1 (13%)	2 (40%)
Regulator	4 (8%)	1 (11%)	11 (41%)	15 (83%)	0 (0%)	2 (40%)
IPPs	9 (19%)	7 (78%)	9 (33%)	15 (83%)	1 (13%)	5 (100%)
Restructuring	4 (8%)	4 (44%)	14 (52%)	13 (72%)	3 (38%)	2 (40%)
Gen privatization	2 (4%)	2 (22%)	10 (37%)	7 (39%)	1 (13%)	2 (40%)
Dis privatization	2 (4%)	1 (11%)	8 (30%)	8 (44%)	1 (13%)	1 (20%)
Reform indicator	0.88 (15%)	2.44 (41%)	2.70 (45%)	4.28 (71%)	1.00 (17%)	3.00 (50%)

Source: Bacon and Besant-Jones (2002:8)

Notes: AFR: Africa; EAP: East Asia and Pacific; ECA: Europe and Central Asia; LCC: Latin America and the Caribbean; MNA: Middle East and North Africa; SAR: South Asia, Gen: Generation; Dis: Distribution. Shading added by author.

By 2000, the World Bank surveyed 116 developing countries, albeit not according to the Scorecard metric, and progress was noted. For example, industrial firms in 17 countries had a choice of power supplier; independent or quasi-independent regulators appeared to be working in 37 countries; and in 27 countries private sector participation was deemed to be significant. There was, however, little evidence for true competition at the generation and retail level (Bacon and Besant-Jones 2002:8, 2000 analysis cited).

Among the latest and most extensive surveys of reform steps taken was reported in John Besant-Jones (2006), results for which are summarized in the table below. Again, these do not map to the 1998 Scorecard steps. Commercialization, corporatization, passage of requisite energy legislation and establishment of regulator, have not been noted, but instead are implied by the current structure of the ESI. Furthermore, it is important to note that retail competition is not featured as one of the categories,⁴⁶ as it is deemed largely inapplicable to the sample of developing countries (Besant-Jones J.E. per com 2007). Instead, what is featured are the models presently predominating among developing countries, namely vertically integrated monopolies, with and without IPPs (see rows A & B below) as well as varying degrees of wholesale competition (see rows C through E below).

⁴⁶ Retail competition is only included in terms of "aggregators of retail demand that buy into the wholesale market," (Besant-Jones J.E. per com 2007).

Table 2.2: ESI Structure in 150 Developing Countries

Group	Current structure of power supply	Number of countries
A	Vertically integrated monopolies	79
B	Vertically integrated monopolies with IPPs	36
C	Single buyer as a national genco, transco or disco OR a combined national genco-transco or transco-disco + IPPs	16
D	Many discos and gencos, including IPPs, transco as single buyer with third party access	6
E	Power market of gencos, discos and large users, transco and ISO	13
	Total countries	150

Source: author's compilation based on Besant-Jones (2006:22)

Notes: genco: generation company; transco: transmission company; disco: distribution company

Regional trends have continued with Latin America and the Caribbean being the forerunner in terms of advancing toward full privatization and competition, followed by Europe and Central Asia. Sub-Saharan Africa meanwhile continues to represent the largest number of vertically integrated monopolies (39). These regional trends are in turn reinforced by size of ESI and income per capita. No country with less than 1,000 MW installed is operating a wholesale market (either group D or E above). Furthermore, in terms of low income countries (defined as US\$765/annum or less), there is no evidence of the most developed form of wholesale competition (group E above), and only one example of the second to most developed form of wholesale competition (group D above). The majority of low income countries (43) appear to be vertically integrated monopolists, with some (15) having introduced IPPs (Besant-Jones 2006:23-24).

Two main points are worth making in conclusion. First, in her assessment of power sector reform, Hunt observes that no country that has introduced competition has reverted to a monopoly (2002:5).⁴⁷ However, the second point, is that in their survey of Brazil, China, India, Mexico and South Africa, Victor and Heller note that full implementation of the textbook reform model is not evident in any one of the countries, which are noteworthy for having the biggest power systems within their respective regions as well as among the most rapid growth in electricity demand in the world (2007:xv, 256). Besant-Jones reinforces this point as he notes that only about 20 developing countries have introduced wholesale competition and that retail competition is negligible (2006:22; 2007). In abundance, however, are vertically integrated monopolies as well as such monopolies with IPPs (see A & B in Table 2.2). The model for power sector reform, although widely propagated throughout developing countries, was, in the end, only taken up in part.

⁴⁷ This point is also made by Bacon and Besant-Jones (2002:15) who note in concluding that despite macroeconomic shock that impacted unfavourably, particularly on IPPs, the liberalization programme has not been reversed or undone.

2.6 New imperative for FDI at the inception of power sector reforms

Thus far, it has been shown how IPPs were part of a much larger model of power sector reform; ultimately, however, the projects came to be among the most visible vestiges of the reform model as other pieces were either unsuccessfully implemented or not implemented at all. This section contextualizes IPPs within foreign direct investment by examining one small part of the investment literature, viz. the theory of the obsolescing bargain, to further elucidate how and why IPPs were shaped, which is expected to shed further light on the analysis of such projects in Africa.

As previously discussed, cash-strapped utilities characterized many ESIs across developing countries, at the inception of power sector reforms. This condition was the result of myriad factors, detailed in section 2.4.1, including decades of below cost tariffs, which were themselves partly the result of development policies in which provision of electricity was considered a public good (World Bank 1993a:32). The lack of investment capital was not, however, unique to utilities, but, it may be argued, is among the defining features of developing countries.⁴⁸ Thus not only were the coffers of the utilities largely empty (and often indebted), but other sources of both public and private financing were not available.

Meanwhile, the investment needs for the power sector were and continue to be huge. Developing countries need approximately US\$5.2 trillion new investment to meet the projected increase in electricity demand and to replace old infrastructure between 2002 and 2030 (International Energy Agency 2004:191).⁴⁹ In 1990, it was estimated that required capital expenditure for power expansion programmes for developing countries in the 1990s would amount to approximately US\$1 trillion (in 1989 US dollar terms), with the majority of the investment (60 per cent) needed for generation. Asia was expected to require over 60 per cent of the investment, followed by Latin America (20 per cent), Middle East and North Africa (16 per cent) and Africa a mere 2 per cent (Moore and Smith 1990:i,12).⁵⁰

⁴⁸ The most widespread definition for developing countries is based on income per capita, with the most frequently cited source the World Bank's index, based on gross national income (GNI), which groups countries as low income, lower-middle-income, upper-middle-income and high-income, with all, save the high-income countries, considered 'developing countries'. Another recognized means for judging developing countries is based on their international indebtedness (Todaro and Smith 2003:34; World Bank 2006a), with 22 of the 42 severely indebted countries as of 2003 in the African continent (World Bank 2005a:262-4). Severely indebted is defined by "the 'present value of debt service [of a country being] greater than 220 per cent of exports or 80 per cent of GNI,'" (World Bank 2005a:265).

⁴⁹ Projected investment figures do not assume any large increases in access levels, as discussed in greater detail in Chapter three.

⁵⁰ These figures were based on growth rates and system expansion plans, developed by the electric utilities in the LDCs, generally with the approval of governments. Some adjustments were made by the authors, however, still, "in general, the forecast is probably too high, because it does not take into account the limited availability of funds for the power expansion plans in some countries," (Moore and Smith 1990:2).

Although in the decades leading up to the 1990s, development finance institutions had provided significant funding to address financing shortages,⁵¹ the emerging consensus, as described in the previous section, was that the private sector could more effectively do the job of building and operating power plants. Thus concessionary lending for the ESI, while not stopped, was reduced, certain conditions were extended that attempted to integrate commercialization and private participation, and (more) space was made for the private sector to step in.⁵² Thus the imperative for FDI was clear.

While the investment need is great, the experience of IPPs has also been mixed. As previously noted, investment levels peaked and have since declined. Many IPP contracts have also faced severe stress. Why? Does the literature and theory of FDI help explain this experience?

2.6.1 The obsolescing bargain (within FDI)

While it is beyond the scope of this thesis to conduct an extensive review of the FDI literature, what is undertaken is a review of the theory of the obsolescing bargain, which forms part of the FDI literature and on which the Stanford PESD IPP study drew in its analysis to evaluate IPP experiences across developing regions (Victor, Heller et al. 2004:15; 2006a:127-9,189,219). It should be noted at the outset, however, that the PESD analysis also drew on a wide series of additional ideas, which will be treated in greater detail, following this discussion of the obsolescing bargain.

By way of background, the obsolescing bargain was coined by Raymond Vernon, in *Sovereignty at Bay*, to help explain how governments (both industrialized and developing) and multinational corporations interfaced (Vernon 1971:53).⁵³ Vernon wrote at a particularly sensitive time. Between 1956 and 1972, just less than 25 per cent of the foreign capital stock in

⁵¹ As one example, highlighted in section 2.4.2, in the 1980s, the World Bank funded approximately 7 per cent of total power investments in developing countries (World Bank 1993a:34).

⁵² In commenting on the estimates of approximately US\$1 trillion and 385,000 MW, Adamantiades, Besant-Jones and Hoskote wrote in 1995, “the vast financial demand for investments in electricity supply in DCs [developing countries] has major implications for macroeconomic policies as well as for power sector financing, including from multilateral lending institutions such as the World Bank (Adamantiades, Besant-Jones et al. 1995:2), italics added by author. As noted previously (section 1.1), although multilateral funding agencies largely withdrew from state-sponsored projects, they continued to play a critical role through providing technical assistance as well as funding privately-led deals, such as Songas.

⁵³ Although obsolescing bargain has become synonymous with Vernon and *Sovereignty at Bay*, the idea was one of many presented in the 1971 book. The thrust of the book was not to lay out the obsolescing bargain but rather to document the spread of multinational corporations (particularly USA-based) and describe how multinationals (often backed by their own sovereign states) with multiple jurisdictions are not on equal terms with the allegedly sovereign states in which their subsidiaries do business. Vernon, reflecting on how the book had been misread/remembered, wrote in 1981, “...I am brought back to what I regard as the central question. How do the sovereign states propose to deal with the fact that so many of their enterprises are conduits through which other sovereigns exert their influence?” –a question that appears to be in line with this thesis’ focus on development and investment outcomes (Vernon 1981:529).

developing countries was nationalized, with compensation provided for about 40 per cent of such stock. The most targeted sectors were mining, agriculture and public utilities (Williams 1975:267,270,272).⁵⁴ Vernon's idea, which was based on experiences in raw material extraction, particularly the global copper trade, is that at the inception of a large foreign investment in a developing country, the scale is tipped in favour of the investor, who brings much needed capital, technology and skill. Vernon clearly differentiates how scenarios differ in developing countries and industrialized countries, where he argues there is less imbalance at contract signing as the industrialized host country does not need to make as many concessions (as the developing country) to attract investors and assuage risks (1971:55). Once, however, the investment has been made, debt has been repaid, and the (developing) host country has increased its own skill and understanding of the trade, resistance may begin to build, especially with regard to any dividends paid out to shareholders. At this time, the original bargain may become obsolete and risk of expropriation of income and assets increased.⁵⁵

The obsolescing bargain has been cited consistently since it was first used by Vernon in 1971 to explain potential tension in foreign direct investment.⁵⁶ Furthermore, the theory of the obsolescing bargain has long since been brought to bear to the analysis of large infrastructure projects, including IPPs, which have large fixed capital components that could not easily be moved (Wells and Gleason 1995:52)—with the Stanford PESD IPP study, discussed in detail below, among the most recent examples.⁵⁷

There were several conclusions that stemmed from the obsolescing bargain. One such conclusion, as articulated by Levy and Spiller in analyzing telecommunications regulation, as cited by Stanford PESD, is that private ownership may be safeguarded through “inflexible regulatory regimes” that constrain “arbitrary administrative action” (1994:202,241). At the heart of Levy and Spiller's analysis was the recommendation for a regulatory governance structure that limited such arbitrary action, but also extended a series of regulatory incentives to reward good performance (241), enshrined in an iron clad PPA.⁵⁸

⁵⁴ Kobrin's analysis details developments between 1960 and 1976, and finds an increase of divestments overtime with the majority occurring between 1970-1976 and reflecting among other things the divestiture in petroleum-related activities (1980:77,79).

⁵⁵ There are parallels between Vernon's obsolescing bargain and 'asset specificity' as defined by Oliver E. Williamson to describe “bilateral dependency by reason of investments in transaction specific investments” (Williamson O. E. per com 2007). Neither author appears to acknowledge the relationship, however, in print with asset specificity formally defined in 1976 in William's, with prior mention dating back to 1971 (Williamson 1971; Williamson 1976).

⁵⁶ The academic database Journal Storage (JSTOR) includes over 50 articles with references to 'Vernon' and 'obsolescing bargain' between 1976 and 2003 with references approximately equally dispersed over two and a half decades.

⁵⁷ Three recent books which include reference to the obsolescing bargain, specifically in the context of analyzing infrastructure investments, are: Victor and Heller (2007:10), Moran (2006:78-79, 116), and Wells (2007: 162).

⁵⁸ An important caveat, albeit largely overlooked in actual practice, is made for countries with insufficient institutional capacity (to enact such regimes), where it is suggested that privatization

Yet another possibility, as documented in Wells, and also noted in the Stanford PESD IPP study, is that a spate of “new protections” were developed in the 1980s, including more robust political risk insurance (PRI), and an international system of arbitration backed by bilateral investment treaties and regional trade agreements (Woodhouse 2006a:130-1; Silverthorne 2007; Wells and Ahmed 2007:5-6). Although in existence since the post-World War II period, the coverage of PRI providers have grown significantly since then, along with the number of such providers. Presently PRI providers number over 80, mainly led by national export credit agencies, most notably the Japan Bank for International Cooperation (JBIC) as well as a number of private insurers such as Lloyd’s and AIG, and the Overseas Private Investment Corporation of the United States (OPIC) (Multilateral Investment Guarantee Agency 2007; Wells and Ahmed 2007:5). More recently, multilateral development institutions, including the World Bank Group (via the Multilateral Investment Guarantee Agency, MIGA), ADB, and IADB have also introduced forms of PRI, with the standard product, guarantees for loans and equity investments from currency convertibility and transfer risk, full or partial expropriation of assets as well as damage or loss of income due to politically related developments including war (Razavi 1996:133; Sinclair 2007).⁵⁹ Another more recent product to safeguard investments are partial risk guarantees (PRG), which in the case of the World Bank’s product, must be backed by a counter guarantee by the government, protects private lenders from the risk of a public entity failing to fulfill certain obligations it has undertaken, and may be tailored to deal with any or all of the following, including: tariffs, regulatory risk, collection risk, arbitration, change in law, convertibility, transferability and subsidy payments (Sinclair 2007:37-36). The main distinction between PRI and PRG is that the former is concerned primarily with politically based risks while the latter is generally focused on commercial risks (albeit commercial risk that are affected by government action) and may be more easily geared to one specific risk.

Still other possibilities were joint venture partnerships including with local firms as well as technological selection. Each of these protections was expected to reduce the risk that the contract would unravel (and if it did unravel, firms would not experience the same losses as they did in the 1960s and 1970s).

2.6.2 Obsolescing bargain and IPPs

As noted previously, it is the Stanford PESD study, which has brought the concept of obsolescing bargain to bear directly on the IPP experience, most recently and arguably with the

programmes that distribute share ownership to large parts of the population may be a better alternative for precluding possible conflict (Levy and Spiller 1994:241).

⁵⁹ It should be noted that IDB provide coverage against neither expropriation nor political violence; furthermore, the activity of these organizations in this area is limited.

greatest depth.⁶⁰ What PESD documents is that for IPPs throughout the 1990s among the most common responses to the possibility of the obsolescing bargain was to create increasingly detailed and stringent contracts between government and investor as well as arrange significant securities (such as escrow accounts and liquidity facilities) and credit enhancements (such as partial risk guarantees, sovereign guarantees and political risk insurance). Project partners were also selected with a view to warding off any encroachment by the host country government, and, should conflicts escalate, international arbitration was set up (Woodhouse 2006a:131). PESD termed this approach 'risk engineering' (Woodhouse 2006a:125,151).

What were the results of the Stanford PESD review of more than thirty projects across thirteen developing countries? There appear to be mixed outcomes recorded in the majority of projects. Does this in turn mean that the obsolescing bargain did not occur across the entire sample? Were the risk engineering strategies outlined above sufficient to counteract the encroachment of the state in most of the cases?

On the one hand, the Stanford PESD IPP study found evidence for the obsolescing bargain in Argentina, China and India. To consider one such example, Argentina, which saw its currency devalue by 200 per cent in 2001-2, has evidenced what might be termed a variation of obsolescing bargain, with the freezing of tariffs and the conversion of payments into pesos (Nuñez-Luna and Woodhouse 2005:2,12,19; Woodhouse 2006a:153). On the other hand, in Egypt, Malaysia and Thailand, which all experienced significant devaluations (of 50 per cent, 60 per cent and 50 per cent respectively in 2002-3 and 1997-8), the Stanford PESD IPP study reported that the obsolescing bargain did not hold significant explanatory power in explaining outcomes.⁶¹

Furthermore, contrary to expectation, the Stanford PESD IPP study found that the abovementioned risk engineering strategies, were not sufficient in warding off the obsolescing bargain where it has been evidenced. Among the most high profile IPPs, which had arguably some of the most robust risk engineering was India's Dabhol Power Company (DPC). Hailed as the largest foreign direct investment by 1993 in India, DPC, a 2015 MW plant, had all the safeguards that would prevent obsolescing bargain. The deal was backed by a 20 year PPA, with tariffs indexed to Indian inflation. Both the Government of Maharashtra and the Central Government provided guarantees should the utility (MSEB) default on payment (Gratwick 2002:4-5). An escrow account based on cash collections from other MSEB regions was also established. The World Bank, while not a partner, per se, had been instrumental in bringing about what was perceived to be a more balanced agreement through its strong disapproval of

⁶⁰ As with Vernon, however (see footnote 53), the findings of the PESD work (Woodhouse 2006a) should not be reduced to one theme. The work, which, as noted in footnote 9, spanned over two years and was reported in more than a dozen case studies, had a larger approach of which the obsolescing bargain was only part.

⁶¹ Other potential explanations, beyond the obsolescing bargain, are the subject of section 2.7.2.

initial contract terms (Gratwick 2002:4,9; Lamb 2006:50). Finally, provisions for international arbitration were established. Despite these myriad safeguards, the original bargain did obsolesce and investors found themselves without the payment streams they anticipated.⁶²

Thus Stanford PESD found that while the obsolescing bargain does not explain outcomes across the entire pool of projects, and that the risk engineering strategies were often not effective, it does help to describe the context in which certain projects and countries respond to stresses (Woodhouse 2006c:10). In the words of the primary author, “projects remain vulnerable to the obsolescing bargain, but many...other independent variables [have been] more directly traceable to observed variation in outcomes” (Woodhouse E. J. per com 2007). With the African sample characterized in part by a relatively weaker investment climate and with a substantial number of IPPs undergoing some form of contract change, the obsolescing bargain may hold explanatory power here as well.

2.7 Towards an analytical framework for understanding IPP outcomes

Two of the larger contexts in which IPPs developed have been sketched thus far, together with bodies of relevant literature and theory. Not only do these theoretical contexts point to critical issues to be taken up in the review of empirical data, but they also, as previously indicated, may be revised and embellished, based on the empirical evidence unearthed by this thesis. With this backdrop, it is now time to turn to the analytic framework used to evaluate the IPP experience, which will be followed by an in-depth treatment of the experience in several African countries. This framework, which seeks to enhance the understanding of development and investment outcomes in African IPPs and ultimately improve sustainability in future projects, builds on an existing body of literature on IPPs, described immediately below.

2.7.1 IPPs reviewed

Substantial reviews of independent power projects have been conducted in recent years. Rather than summarizing these reviews in detail, the section below extracts key lessons and identifies critical factors that help to explain outcomes.

In the previously cited work, *Regulation, Deregulation or Reregulation--What Is Needed in the LDCs Power Sector*, the authors cautioned against the applicability of IPPs for less developed countries, given long, inflexible contracts, which demand a high premium for investors (World Bank 1990:70). A subsequent, though less severe, warning appeared in the World Bank's 1993 electric sector power policy. In reflecting on the experiences of India, Indonesia, Pakistan, and Turkey (among the earliest developing countries to introduce large-

⁶² This section also draws on the analysis of IPPs presented by Thomas C Heller on October 25, 2005 at the Management Programme in Infrastructure Reform & Regulation course, “Independent Power Producers: Frontiers in International and African Experience,” at the University of Cape Town's Graduate School of Business.

scale IPPs), the World Bank indicated that country governments have rushed after large and risky projects, rather than approaching such new investments slowly through small-scale ventures, which is the preferred approach. Further difficulty has resulted due to the failure “to address fundamental problems of governance, specify a clear legal and contractual framework, put in place an arm’s-length transparent regulatory structure, or allow commercially-based tariffs that reflect real costs” (World Bank 1993a:51-52). Thus, although IPPs were often taken up as a quick and easy reform step, their ultimate success was contingent on a host of other factors.

There has been little change in the consensus about the conditions that may yield favourable IPPs results. Key elements noted in the mid-1990s, and reiterated over the decade, may be broken roughly into two categories: the investment environment and the project itself. In terms of the investment environment, paramount is a clear political commitment including coordination among ministries (World Bank 1993a:52; World Bank and USAID 1994:5; Hoskote 1995:10). Ideally, this translates into a clear framework for policy making and subsequently, provided there is sufficient capacity, clear policies, including an independent regulatory mechanism that results in predictable tariffs and hence revenue that will service debt and reward equity (APEC Energy Working Group 1997:11,16; Bacon and Besant-Jones 2002:15; Lamech and Saeed 2003:9; Fraser 2005:14).⁶³ Also widely noted in terms of improving the probability of success for IPPs is a commercially run sector with cost-reflective tariffs and effective billing and revenue collection (Hoskote 1995:2; APEC Energy Working Group 1997:12; Lamech and Saeed 2003:9-10).

At the project level, conditions that may lead to favourable outcomes include smaller scale projects, which are potentially less visible; that is, the impacts of higher prices for new IPP investments may be more readily absorbed (World Bank 1993a:51; Hoskote 1995:10; Fraser 2005:13-14). A well-managed competitive bidding process has been generally noted to help avoid corruption and result in lower costs (World Bank and USAID 1994:36,44; Hoskote 1995:3; APEC Energy Working Group 1997:19; Asian Development Bank 2000:71-2).⁶⁴

⁶³ A critical aspect for investors in the utility sector, cited by Lamech and Saeed is the “independence of regulatory institution[s] and processes from arbitrary government interference” (2003). A second recent study reinforces these findings, ranking “regulatory uncertainty” as among the greatest concerns of investors in the utility sector (PricewaterhouseCoopers 2005:6). A third study reports that “80% of their respondents said that political and regulatory factors are inhibiting the ability of the sector to respond to the immense change challenge ahead,” (PricewaterhouseCoopers 2006:9).

⁶⁴ After surveying IPPs throughout South Asia, a recent study found that there was no conclusive evidence for lower cost PPAs resulting from competitive bids (rather than selective bidding). The study did, however, note that, “in many instances competitive procurements can lead to lower prices”. This view is supported by the theory of competition for the market. There may also be methodologies for non-competitive procurement that are transparent and that lead to low price outcomes. It is reported that in the Chinese IPP programme, the government representatives used an effective negotiating process to reduce both the equity returns and the costs associated with their IPP plants,” (Deloitte Touche Tohmatsu Emerging Markets Ltd. and Advanced Engineering Associates International 2003:24). Drawing on the Deloitte work, the Stanford PESD IPP study as well as independent analysis, another recent study

Robust and transparent power purchase agreements as well as additional revenue security measures, such as escrow accounts, and credit enhancements such as sovereign guarantees have been outlined as best practices (World Bank and USAID 1994:22; Hoskote 1995:9-10; International Finance Corporation 1996:34). In addition, the benefits of various mechanisms to deal with potential currency mismatches between financing and revenue streams, for example hard-currency denominated power purchase agreements (PPAs), or alternatively the involvement of local capital is mentioned in the review of projects (Hoskote 1995:11). Also cited is the role of strong local management in contributing to project successes and the presence of local capital (International Finance Corporation 1996:34).⁶⁵

Emphasis on the importance of the power purchase agreement, outlining the relationship between the investment environment/host country and the project, has been extensive. Setting the right terms and conditions has been recognized as among the most critical aspects of developing, operating and maintaining IPPs successfully, including determining the initial ownership structure (i.e. whether the plant will ultimately be a build own operate (BOO), build own operate transfer (BOOT) or a build operate transfer (BOT)) (Sader 1999:12; Asian Development Bank 2000:72,75). Key elements identified within the PPA include the obligation of the project sponsor to provide a set capacity and availability as well as the obligation of the off-taker to pay a set amount for such capacity, generally regardless of whether the capacity is used or not, for the duration of the contract, and energy charges which allow appropriate pass through of fuel costs (APEC Energy Working Group 1997:13-14; Marais 2006:3). This contractual agreement minimizes market risk for the project sponsor and helps to ensure availability for the off-taker, but also comes with the risk of over-capacity and high charges should the project's power not be demanded, or the ESI moves toward wholesale competition (Woolf and Halpern 2001:6). The way in which plants are dispatched, metering, interconnection, insurance, *force majeure*, transfer of assets (in the case of BOOT), contract termination, change of law provisions, refinancing arrangements, dispute resolution are all generally stipulated as well (World Bank and USAID 1994:88-92; International Finance Corporation 1996:118-126).

Increasingly, emphasis is being placed on making PPAs into more sustainable documents, by considering special provisions related to the operational, financial, regulatory and legal

focusing exclusively on CCGT IPPs in eight countries (Bangladesh, India, Indonesia, Malaysia, Pakistan, The Philippines, Thailand and Turkey) goes one step further. The author demonstrates that the stated capital costs of competitively bid projects is generally 40 to 60 per cent lower than those via direct negotiation (Phadke 2007:11,24).

⁶⁵ It should be noted that with regard to the International Finance Corporation' (IFC) lessons learned cited above, they apply generally to IFC's portfolio of infrastructure investments in the mid-1990s, however, power generation accounted for almost 50 per cent of the portfolio in 1996—greater than any of the other eight infrastructure sectors (International Finance Corporation 1996:35).

aspects of the contract. The overarching goal is for the contract to provide security to the seller without pitting buyer and seller against one another, given market dynamics and unanticipated events and circumstances. Much of the discussion focuses on building more incentives and penalties into contracts, including, for instance in the case of providing additional power (Woolf 2005:12). Buy-out provisions are also a means to reduce the impact of cheaper power, should it become available (Woolf and Halpern 2001:21; Woolf 2005:17). Sharing the gains of refinancing (between buyer and seller) is another possible means to increasingly sustainability. In each of these cases, however, the issue must be clearly specified in the PPA at contract signing. Even then, many shareholders and debt-holders alike may not agree to such sustainability provisions if they sense a potential threat to their payment streams (Sheppard R. per com 2006).

Among changes related to assessments of IPPs over the decade is the treatment of macroeconomic shock, which impacted significantly on IPPs, particularly in East Asia after the Asian Financial Crisis of 1998. Best practices have subsequently developed to include more mitigation measures to deal with currency devaluation, including seeking increased local capital, which although emphasized at the beginning of the decade was not considered essential (Matsukawa, Sheppard et al. 2003).

2.7.2 The Stanford PESD IPP study

The recent Stanford PESD IPP study, cited repeatedly in the Introduction and throughout Chapter two in the context of the obsolescing bargain, has significantly advanced the understanding of the causes related to IPP successes and failures. Selecting a wide range of country and project experiences, the Stanford PESD IPP study set out to identify explanatory variables that determined project successes and failures as well as identify key lessons for investors and host country governments alike (Victor, Heller et al. 2004; Woodhouse 2006a).

Through literature reviews as well as in-depth interviews carried out by researchers, the study identified five hypotheses, which could potentially serve as broad explanations for outcomes, viz. the obsolescing bargain, the investment climate, the electricity market, project management and exogenous events and contagion (Victor, Heller et al. 2004:15-22,52-58). In terms of the obsolescing bargain, as previously discussed, Stanford PESD sought to ascertain whether original deals became unstuck once investments were made or whether a series of strategies, including iron clad PPAs, technological selection and joint investment helped mitigate the effects of encroachment by the host country government. With regard to the investment climate, the second hypothesis, here the study was interested in evaluating the extent to which the investment climate, as defined by the legal context, the state of public finance, financial markets and FDI experience, among others, was the determining element in outcomes. The third hypothesis looked at the way in which the electricity market, characterized

by its (attention to or lack of) IPP framework, estimated demand, independent regulator and payment systems, impacted on outcomes. Project management, the fourth hypothesis, inquired whether the ways deals were first negotiated and subsequently managed, both from an operational and financial perspective, provided the key to understanding variation in project outcomes. Finally, the last hypothesis, exogenous events and contagion, posited that events, such as the Asian Financial Crisis, were the chief determinant of results.

The analytical framework did not stop there. Rather, a series of factors, which were grouped into country level and project level factors, were linked to each of the hypotheses. It is important to note from the outset that there was considerable overlap between the hypotheses and the factors; however, the purpose of the two was different. It was expected that one or more of the hypotheses held the grand explanatory power for outcomes while the factors were first used to select the cases and subsequently as a means for testing the validity of the different hypotheses. Country level factors comprised: the macroeconomic context, political and social context, legal and regulatory framework, electricity market and fuel markets (Victor, Heller et al. 2004:32-4; Woodhouse 2006a:139). Project level factors comprised: investor composition, IPP programme, financial arrangements, fuel and technology choice, and operations and maintenance (Victor, Heller et al. 2004:41-3; Woodhouse 2006a:139). In addition, the global industry downturn was added to the list of factors as impacting outcomes.

As indicated above, the universe of IPPs in developing countries was identified and countries (with IPPs) were selected based on the variation that they demonstrated with regard to the country level factors.

For instance, at the inception of the first IPPs, Poland's incumbent fuel was coal while Brazil's was hydroelectricity (Victor, Heller et al. 2004:36,40). Investors in Mexico were shielded from macroeconomic shock while those in Argentina were directly exposed to it (Victor, Heller et al. 2004:36-37). Each of the other countries—China, India, Malaysia, Mexico, The Philippines, Thailand and Turkey—displayed an equally wide range of characteristics, with regard to the country level factors. After this initial country selection, projects in each of these countries were identified for in-depth analysis based on the variation that they demonstrated across the series of project level factors (Victor, Heller et al. 2004:32-34,41-43; Woodhouse 2006a:138-9). The project pool eventually came to contain 13 developing countries and 34 projects.

After two years of research, which hypotheses emerged as the key to understanding the variation in development and investment outcomes for IPPs? As discussed in section 2.6.2, the obsolescing bargain and the associated risk engineering instruments used to ward off the obsolescing bargain were helpful in explaining many contexts, but did not predict outcomes across the entire pool. Detailed examination of the investment climate hypothesis led to several interesting insights, including the fact that project developers did not avoid countries with

perceived corrupt business environments, and that reliance on sovereign guarantees in such environments was nearly universal (Woodhouse 2006a:156). This analysis, like that of the obsolescing bargain did not, however, yield a grand explanation for the variation in outcomes seen across the project pool.

An in-depth review of exogenous shocks and contagion confirmed that this hypothesis indeed explained many outcomes of IPPs, particularly those in Argentina (as previously noted) and Indonesia, which was also a victim of severe macroeconomic shock and currency devaluation. However, as discussed earlier in the context of the obsolescing bargain, some IPPs in countries that experienced significant exogenous shocks, were, however, protected—notably those in Thailand (Woodhouse 2006a:152-154). Again, as with the other hypotheses, exogenous shocks and contagion, while helping to clarify a range of particular experiences, in the final analysis did not offer an explanation for all projects reviewed.

With regard to the electricity market, although this hypothesis ultimately proved lacking in explaining outcomes for the group of projects, Stanford PESD provided a particularly important discussion of the new market and new firms, which emerged from power sector reform (Woodhouse 2006a:210-214).⁶⁶ As reform has only been piecemeal in its implementation, it has led to the creation of organizations and interests that are partial to a new equilibrium. The study terms this new equilibrium a hybrid/dual market, which is a combination of aspects of a state-centred and market-centred electric power systems, (Woodhouse 2006a:210-214; Victor and Heller 2007:260). Within this dual market, it is “the dual firm” characterized by political connections and commercial practices, which thrives, and which in the end itself may impede further reform a la standard model.

Thus, the four hypotheses noted above were significant, but ultimately limited in their explanatory power. It was only project management, later termed strategic management, that emerged as yielding explanatory power across the pool (2006a:126,172,185,212). Strategic management was contrasted with risk-engineering, which had often not held in the face of adversity. The most successful IPPs from both a development and investment perspective, as found by the Stanford PESD IPP study, were those in Egypt, Malaysia, Mexico, The Philippines and Thailand (Woodhouse 2006a; Woodhouse 2006b). Characteristics of the most successful projects are summarized as falling into three different categories: 1) project selection and cost, 2) local partnerships, and 3) project governance (Woodhouse 2006c:13).

For example, project selection, namely internationally competitive bids, was instrumental in helping to reduce tariffs and increase transparency, which in turn helped projects weather the storm of macroeconomic shock, particularly in Egypt and Thailand. Local partnerships, evident in more than half of the project’s sample (and virtually all projects in Malaysia), have been

⁶⁶ This discussion is expanded in Victor and Heller (2007).

found to be especially valuable in mitigating dispatch risk and managing renegotiations (Woodhouse 2006a:146-7,193-4; Woodhouse 2006b:20).

The last item, 'project governance', pertains to how within often tight project-financed agreements, stakeholders (primarily governments, through centrally controlled agencies and/or departments with significant resources at their disposal) were able to make concessions, which ultimately eased project stresses and led to more mutually beneficial outcomes (Woodhouse 2006a:203,206; Woodhouse 2006c:15). Prime examples are IPPs in Thailand and The Philippines. Mexico's experience also comes to mind here with US dollar denominated liabilities associated with IPPs kept off the government's balance sheet, identified as non-bank private sector borrowing via the Pidiregas scheme (Woodhouse 2006a:147-8). Although the sustainability of this scheme is being called into question, it went a long way in attracting and cementing IPP investment in Mexico by providing (the appearance of) a secure investment environment.

To reiterate, it was the strategic management of projects, particularly when faced with stresses, to which success may be linked. The emphasis on strategic management also helps explain why, although 21 of the 34 projects experienced some form of renegotiation, only four out of the 34 are perceived to have resulted in negative investment outcomes (Woodhouse 2006b; Woodhouse 2006c:10).⁶⁷ Within this context, Orr describes how the Stanford PESD IPP study argued that every attempt should be made to create more flexibility with regard to contracts, albeit accepting that risks need to be adequately assigned (2006:20-21). This is not necessarily a plea to create more flexible contracts, which Stanford's PESD recognizes as not viable to date, but more flexible counterparties and ultimately more 'political good will' to manage stresses when they (inevitably) do arise (Woodhouse 2006c:21-22).

As detailed throughout this section, Stanford PESD made a significant contribution to the understanding of IPPs across developing regions. There are, however, three main shortcomings identified by this author.⁶⁸ First, although claims were made to focus on the development and the investment outcomes, there was not a systematic link between hypotheses, factors and outcomes throughout the study. In the 2005 interim report, scant attention was paid to development outcomes, and investment outcomes were only discussed on the margin (Woodhouse 2005). In the final study, published a year later, the treatment of development and investment outcomes re-emerged, primarily in the synopses of each of the countries, but it is

⁶⁷ The four projects reported to have resulted in negative investment outcomes are: China's Miezhouwan, a group of five projects referred to as the Tamil Nadu IPPs, the Philippines' Cavite and Poland's Elcho (Woodhouse 2006b:11,17,25,27). In addition Tanzania's IPTL was reported as having "mixed/negative outcomes" (Woodhouse 2006b:27).

⁶⁸ A fourth point, of lesser importance, is the fact that 'strategic management' and 'risk engineering', although the cornerstone of the final analysis are nowhere to be found in either the Methodology or in the Interim Report (Victor, Heller et al. 2004; Woodhouse 2005). Of course both terms may be related to "project management" as widely discussed in the early reports, however, the final analysis does not make this progression clear.

overshadowed by the discussion of risk engineering and strategic management. Although a companion note was produced by Stanford PESD detailing the development and investment outcomes for each project, no such work mapped development and investment outcomes to the factors and hypotheses, across the pool (Woodhouse 2006b).⁶⁹

Secondly, as indicated above, there was considerable overlap between the hypotheses and the factors. For example, the electricity market was both a hypothesis and a country level factor, despite the fact that the country level and project level factors were designed to test the hypotheses. Such overlap has hampered the analysis in proving the validity of its hypotheses, and, as related in the first point above, connecting hypotheses to factors to outcomes and back to hypotheses again.

Finally, insufficient attention was paid to the nuances of the obsolescing bargain. According to PESD, the majority of projects saw a change to the original contract. Due to the fact that the bulk of such changes were deemed relatively positive by investors, the conclusion reached by the study was that the obsolescing bargain was not a chief determinant of outcomes. In contrast, this thesis would argue that the obsolescing bargain is in evidence in virtually every such case. Even if creeping expropriation is curbed by investors, the relatively positive results are less positive than what would have originally been achieved had there been no obsolescing of the bargain.

2.7.3 A new paradigm for understanding IPPs in Africa

In constructing its own analytical framework to evaluate the IPP experience in Africa, this thesis has drawn on the wealth of power sector reform literature, the theory of the obsolescing bargain and earlier IPP studies, most notably Stanford PESD. This thesis used the first two bodies of literature, namely power sector reform and the obsolescing bargain, to frame the context in which African IPPs took root.⁷⁰ The IPP literature, primarily the Stanford PESD IPP study, was the starting point for the actual analysis of projects. At the same time, having identified three main shortcomings above, this thesis jettisoned Stanford PESD's five hypotheses and instead sought to create a direct link between factors and development and investment outcomes.

⁶⁹ Woodhouse (2006b) describes how 13 of the projects evaluated have been found to have positive development outcomes, twelve have had mixed development outcomes and only six have had negative outcomes. It is not, however, a zero-sum game, i.e. development outcomes at the expense of investment outcomes or vice versa as the author finds that investment outcomes across the sample have been largely positive, with 20 of the 31 projects recording investment success, six said to have mixed outcomes and only five projects noted as having negative outcomes.

⁷⁰ Although distinct from the dynamic of IPPs and PPAs discussed in this thesis, it should be noted that Federico Sturzenegger and Jeromin Zettelmeyer (2007) provide insights on how investors manage risks with regard to sovereign debt and sovereign defaults, which may be helpful in advancing thinking and strategizing about the obsolescing bargain as well.

Through empirical work in several African countries, this thesis refined the list of factors, first identified by Stanford PESD, and identified a suite of exogenous stresses, namely macroeconomic shock and currency devaluation, drought, civil strife and (alleged) corruption. Important characteristics reflected in the sample of African IPPs that came to be encompassed by the analytical framework (both the elements and stresses) include: the important role of civil unrest, especially seen in Nigeria and Cote d'Ivoire; the prominence of the World Bank in shaping electricity sector policy; the role of back-up generators and the relatively less attractive investment climate. Rather than focusing on explaining variation in IPP outcomes, which was the main thrust of the Stanford PESD IPP work, this thesis focused its inquiry into whether balancing development and investment outcomes ultimately leads to more sustainable projects and if so what elements contribute to such a balancing act.⁷¹

The question asked is not only whether the specific IPP project will endure, but also if such projects are replicated, will outcomes continue to be sustainable. In other words, what are the means to both successful development outcomes and successful investment outcomes for the sector and myriad stakeholders, over the long-term, taking into consideration the suite of exogenous stresses that inevitably occur? It should be emphasized here that not only were Stanford PESD's hypotheses jettisoned, but also an attempt to identify one overriding explanation for outcomes, across the pool of projects.

The remainder of this section seeks to describe the main elements, identified through empirical work, which will be evaluated in subsequent Chapters for their possible contribution to more successful and ultimately sustainable outcomes. Elements are grouped roughly into those that fall within the country purview and those that fall within the project purview, namely areas over which either one or the other has a greater degree of control.

What is the role of a *favourable investment climate* in determining development and investment outcomes for IPPs in Africa? A favourable investment climate is generally defined by the following characteristics, among others: macroeconomic policies are perceived as stable; the country has a good repayment record and therefore an investment grade rating from one of the major credit agencies; and the legal system not only is recognized for its general ability to uphold laws, but more specifically to (justly) support the enforcement of contracts, as well as allow space, including via international tribunals, for arbitration. Such a climate may provide more than one investment opportunity to investors and will generally call for less (costly) risk mitigation strategies, which in turn results in a lower cost of capital and more competitive prices—which feed directly into positive development and investment outcomes.

How does a *clear policy framework* impact both host country stakeholders and project sponsors? In such a framework, the electricity market structure and the roles and terms for

⁷¹ See Introduction and footnote 7 for the definition of sustainability adopted by this thesis.

private and public sector investments generally are clearly spelled out, which in the context of African ESIs means with regard to a single buyer model (as there is no evidence, yet, of wholesale competition on the continent). Reform-minded champions may be at the helm, and have a short, mid and long-term view that sees IPPs within a broader vision of reform. Not only may these champions sit at the helm and provide vision, but they also may lead and implement the framework. The key appears to lie in long-term and strong government engagement, without arbitrary (government) interference with the process, which has long been noted to hamper the development of projects.

What is the relationship among *clear, consistent and fair regulatory oversight* and development and investment outcomes? Although part of the abovementioned framework, this element is recognized in its own right, due to its potential importance, and defined by transparent and predictable licensing, as well as a tariff framework that is cost-reflective and therefore ensures revenue sufficiency. Investor confidence should improve with such oversight as should the protection of consumers, together with the performance of both private and public assets.

Intricately linked to the two previously mentioned elements is *coherent power sector planning*, especially in the context of a hybrid market, with both public and private players. Ideally, planning is clearly vested with one agency, which is appropriately skilled, resourced and empowered to carry out its job, including adopting an energy security standard. Duplication of roles and functions is not evidenced. Furthermore, power sector planning fairly allocates new build opportunities, taking into consideration the hybrid market, namely the fact that public and private stakeholders participate (generally with, among other things, different costs of capital). Such coherent power sector planning ensures that built-in contingencies eliminate and/or significantly reduce emergency power and black-outs. How has this element contributed to outcomes in African IPPs?

Do *competitive bidding practices*, long recognized as a *sine qua non*, in terms of best practices, lead to more positive development and investment outcomes? This thesis explores the relationship between ICBs and outcomes, viz. the belief that competitive bidding may result in prices that are lower than those that are selectively bid.

Abundant, low cost fuel may go a long way in contributing to successful outcomes as it often means that the fuel charge of IPPs may be comparable (or even less than) existing, state-owned plants, making overall charges less contentious. Furthermore, secure fuel contracts safeguard the terms for the duration of the PPA, reducing risks for investors and off-taker alike. Whether these dicta hold in the African cases examined here is explored in this thesis.

Table 2.3: Contributing elements to success, within the purview of host governments

CES	Details
Favourable investment climate	<ul style="list-style-type: none"> -Stable macro-economic policies -Legal system allows contracts to be enforced, laws to be upheld, arbitration -Good repayment record and investment grade rating -Requires less (costly) risk mitigation techniques to be employed which translate into lower cost of capital and hence lower projects costs and more competitive prices - Potentially more than one investment opportunity
Clear policy Framework	<ul style="list-style-type: none"> -Policy framework enshrined in legislation -Framework clearly specifies market structure and roles and terms for private and public sector investments (generally for single buyer model, not, yet, wholesale competition in African context) -Reform-minded 'champions', concerned with long-run, lead and implement framework
Clear, consistent and fair regulatory oversight	<ul style="list-style-type: none"> -Transparent and predictable licensing and tariff framework improves investor confidence -Improves general performance of private and public sector assets -Cost-reflective tariffs ensure revenue sufficiency -Consumers protected – improves development outcomes
Coherent power sector planning	<ul style="list-style-type: none"> -Energy security standard in place; planning roles and functions clarified -Power planning vested with lead, appropriate (skilled, resourced and empowered) agency -Power sector planning takes into consideration the hybrid market (public and private stakeholders and their respective real costs of capital) and fairly allocates new build opportunities among stakeholders -Planning has built-in contingencies to avoid 'emergency power' or blackouts
Competitive bidding practices	<ul style="list-style-type: none"> -Procurement process is transparent and competition ultimately drives down prices
Abundant low cost fuel & secure contracts	<ul style="list-style-type: none"> -Cost-competitive with other fuels -Contract safeguards affordable and reliable fuel supply for duration of contract

As previously noted, the elements listed above, with few exceptions such as secure fuel contracts, fall largely within the purview of the host country government. That is, they are the items over which the host country government may exert greater control. One element that has as of yet gone unmentioned is the government's willingness to share risks, both at the inception of projects and through the project life. This element does not fall neatly into one category, but rather may be part and parcel of the many listed both above and those discussed below, as governments take on equity stakes, assist in refinancing and provide guarantees, and help secure competitively priced fuel.

The elements related primarily to the investor purview, which may impact favourably on outcomes, should also have a familiar, commonsensical ring to them. It is important to reiterate in this context, before any further discussion of such elements, however, that many were recorded as best practices over a decade ago. What this thesis attempts, is first to systematically identify such elements and then use them in the evaluation of African IPPs.

What is the link among *favourable equity partners* and development and investment outcomes for African IPPs?⁷² A favourable equity partner is defined here as local capital/partner contribution to reduce foreign exchange exposure and potentially help navigate host-country investment terrain. It may also refer to a new kind of investor with origins in other emerging economies or a firm, which, in addition to a commercial imperative, has a broad development mandate. Having significant and sustained risk appetite for the project, rather than a fleeting interest in a new emerging market appears to lead to more sustainable development and investment outcomes—as does prior experience in similar projects. In many cases, involvement of a development finance institution has proven to help balance and sustain deals. Finally, of significance, is the perception of a fair/reasonable return on equity (ROE) by the wide range of stakeholders, which is often linked to the four abovementioned points (local capital, risk appetite, prior experience and DFI involvement) as well as the host of country level elements already discussed.

While favourable equity partners may go a long way in contributing to balanced outcomes, *favourable debt arrangements* may also be of critical importance—and equally related to the country level elements discussed. Ideally, local financing helps reduce exposure to foreign exchange fluctuations. Beyond that, additional sources of international, low cost financing help keep charges moderate. Much of this low cost financing (local or international) depends on the risk premium demanded by financiers or capped by the off-taker matching the actual country and project risk (rather than perceived heightened risk). The presence of development finance institution, including export credit agencies, might also engender more stability and blunt opportunistic attempts at renegotiation or appropriation. Lastly, although the issue is debated, some flexibility in terms and conditions, including possibly sharing refinancing gains, may ultimately help in the balancing act of outcomes, as indicated in section 2.7.1.

How does an *adequate and secure revenue stream* from the off-taker to service debt and reward equity contribute to successful outcomes for IPPs in Africa? This element is generally defined by several components, namely: the financial viability of the off-taker (through sound commercial practices in metering, billing and collections practices) helps set the conditions for such an exchange. Assurances for timely and complete payment, enshrined in the PPA, by the utility also contribute. Robust PPAs outline capacity and payment as well as dispatch, fuel

⁷² Although favourable equity and debt arrangements as well as risk mitigation measures with the off-taker, fuel supplier and other stakeholders have been classified below as project issues, these elements may relate to the host country as well, considering host country stakeholders are often involved in at least one if not several of these dynamics. Of the elements below, only one may be seen as exclusively within the purview of the project sponsor, namely positive technical performance. Nonetheless, these are all areas where the project sponsor seeks to mitigate risks, either through contracts, or the management of relationships, or both.

metering, interconnection, insurance, *force majeure*, transfer, termination, change of law provisions, refinancing arrangements, and dispute resolution, among others. Safeguarding the PPA with security arrangements (viz. escrow accounts and liquidity facilities), has also proven to maintain such revenue streams, attract favourable equity partners and bring down the cost of capital.

Credit enhancement and other risk management and mitigation measures may include sovereign guarantees, political risk insurance, and partial risk guarantees as well as provision for international arbitration (which may go beyond the dispute resolution provisions specified in the PPA, see above). Sovereign guarantees, provided by the state to the project sponsor, generally back the full value of the PPA, viz. should the off-take default then the government will step in and take over the PPA obligations. Political risk insurance and partial risk guarantees, which as described previously (section 2.6.1), form part of the new protections, drawn on by investors. Increasingly, political risk insurance is being considered for the sub-sovereign level to match the exact risk profile of stakeholders (Sinclair 2007:3,10).⁷³

In addition, projects that record *positive technical performance* (including high availability) may be less likely to face public scrutiny than those that do not, which may therefore impact on outcomes. Finally, *ongoing strategic management* of projects has proven instrumental as projects inevitably face unexpected hurdles, a response for which may not be spelled out in any of the existing agreements. Such strategic management may involve building relationships, including through local equity partners, dedicated budgets for development projects within the country, and even refinancing (as previously indicated under favourable debt arrangements above). Effective strategic management may also involve a willing partner, in the form of the host country government; thus it is not the sponsor alone, but rather a dialogue between sponsor and the off-taker and/or other government entities that enhance such management.

⁷³ It should be noted that although credit enhancements and risk management measures have the potential to lower the cost of capital, these measures also introduce the possibility of moral hazard, namely that the existence of a safety net increases the risk of default and/or political interference. In that sense, these measures may not always contribute to the success of projects.

Table 2.4: Table 2: Contributing elements to success, project issues

CES	Details
Favourable equity partners	<ul style="list-style-type: none"> -Local capital/partner contribution, where possible -Risk appetite for project -Experience with developing country project risk -Involvement of a DFI partner (and/or host country government) -Reasonable, fair ROE -Development-minded firms
Favourable debt arrangements	<ul style="list-style-type: none"> -Low cost financing -Local capital/markets mitigate foreign exchange risk -Risk premium demanded by financiers or capped by off-taker matches country/project risk -Some flexibility in terms and conditions (possible refinancing)
Secure and adequate revenue stream	<ul style="list-style-type: none"> -Commercially sound metering, billing and collections by the utility -Robust PPA (stipulates capacity and payment as well as dispatch, fuel metering, interconnection, insurance, <i>force majeure</i>, transfer, termination, change of law provisions, refinancing arrangements, dispute resolution, etc.) -Security arrangements where necessary (escrow accounts, letters of credit, stand-by debt facilities, hedging and other derivative instruments, committed public budget and/or taxes/levies, targeted subsidies and output-based aid, hard currency contracts, indexation in contracts)
Credit enhancements and other risk management and mitigation measures	<ul style="list-style-type: none"> -Sovereign guarantees -Political risk insurance -Partial risk guarantees -International arbitration
Positive technical performance	<ul style="list-style-type: none"> -Technical performance high (availability) -Sponsors anticipate potential conflicts (especially related to O&M, and budgeting) and mitigate them
Strategic management and relationship building	Sponsors work to create good image in country through political relationships, development funds, effective communications and strategically manage their contracts, particularly in the face of exogenous shocks and other stresses

In sum, this thesis seeks to provide an in-depth analysis of IPPs, focusing on whether balancing development and investment outcomes leads to greater sustainability. That is, do moderate investment returns coupled with moderately priced power mean that contracts are more likely to endure? Might the possibility of the obsolescing bargain mean that sustainability is a function of locking the project up in iron clad contracts, with less attention to ‘balance’ per se? Or, is it inevitable that such contracts will experience stress, including pressure for renegotiation or expropriation, and hence strategic and dynamic management of risk and contracts is advisable? The role of power sector reform including the standard prescription as well as a suite of exogenous shocks are also taken up in this analysis, both to frame the general context and evaluate the extent to which they impact on project sustainability. What other factors may impact? This thesis identifies a series of factors, which it groups roughly into country level factors and project level factors that may affect outcomes. It then goes one step further, reflecting on outcomes and factors, to compile what it deems are contributing elements to success across the pool of African IPP experiences evaluated.

Chapter 3

Africa overview

This thesis situates its empirical work and employs its analytical framework in Africa. Therefore, this thesis now turns to Africa: to review the continent's development status, including a brief discussion of FDI and the investment climate; to discuss natural resource endowments (as they relate particularly to the power sector); to give an overview of African ESI characteristics, and finally to provide a sketch of private participation activity, including IPPs. The data reported in this section is primarily the most up-to-date available (i.e. approximately to 2005), with the overarching goal being to paint a general picture of present conditions to better understand IPP outcomes.⁷⁴

3.1 Development status: Africa

3.1.1 Economic and social development

While there is extraordinary diversity across the 53 countries (and nearly 900 million people, representing about 14 per cent of the world's population) that make up the African continent, in terms of assessing the economic and social development status, the continent may be roughly grouped into North Africa and Sub-Saharan Africa (SSA). Furthermore, it is often useful to separate the relatively more developed country of South Africa (RSA) from SSA.

The gross national income (GNI) per capita for North Africa (at US\$1,700)⁷⁵ falls into the broader category of low and middle income countries and is slightly better than the average for East Asia and Pacific (World Bank 2005a:24; World Bank 2005b:33). A considerable contrast is seen in data for SSA (excluding RSA),⁷⁶ which records the lowest GNI per capita of all regions in the world at an average of US\$342 (World Bank 2005a:24). Furthermore, unlike any other region, GNI per capita in SSA (again, excluding RSA) has been falling, as population growth has outpaced economic growth (World Bank 2005b:33).⁷⁷ Not only has the number of extremely poor doubled since 1981 to 313 million in Sub-Saharan Africa, the relative economic condition has also deteriorated as evidenced by the following: since 1981, the average daily

⁷⁴ More detailed work is, however, presented for Egypt, Kenya and Tanzania in Chapter four through six.

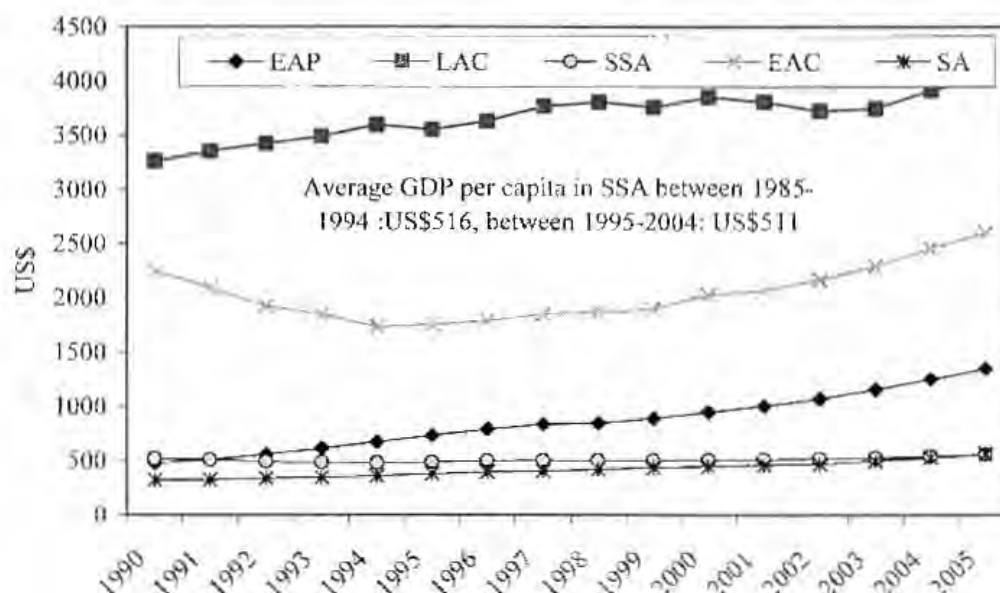
⁷⁵ Data is based on the World Bank's Atlas method, which employs a three year moving average conversion factor, adjusted for price, to reduce fluctuations in the exchange rate.

⁷⁶ The data for South Africa (RSA) will be presented independently for a number of indicators. Although demonstrating extreme income inequality, RSA boasts an average per capita income of US\$2,900 (equivalent to US\$10, 130 in terms of purchasing power parity), which exceeds the average of middle income countries (World Bank 2005a:24; World Bank 2005b:33). Unless otherwise specified in the text, however, figures for Sub-Saharan Africa include RSA.

⁷⁷ Between 1975 and 1984, average annual GNI was reported as US\$420; this dropped to US\$354 between 1985 and 1994 and finally to US\$309 between 1995 and 2003 (World Bank 2005b:33).

income of those people subsisting on less than one US dollar per day has dropped from 64 US cents to 60 US cents (World Bank 2005a:3-4).⁷⁸

Figure 3.1: GDP per capita across developing regions 1990-2005 (in constant 2000 US\$)



Source: compiled by author, based on World Development Indicators (WDI) (World Bank 2007g)

Notes: GDP: Gross domestic product; EAP: East Asia & Pacific; LAC: Latin America and Caribbean; SSA: Sub-Saharan Africa; ECA: Europe & Central Asia; SA: South Asia. North Africa has been excluded due to the fact that data is only available after 1999. It should be note, however, between 1999 and 2005, average per capita GDP was US\$2,000 as reported in WDI.

The trends highlighted above are reflected across a number of social development indicators. North Africa has seen its infant mortality rates drop by more than half to 31 per 1000 births between 1990 and 2003 (World Bank 2005b:313). In contrast, although infant mortality has fallen in SSA since 1990, it is still the developing region with the highest such rates (at just over 100 deaths per 1,000 births) (World Bank 2005a:11; World Bank 2005b:313).⁷⁹ Sub-Saharan Africa also records the highest mortality rates of all developing regions for children under five years of age, at 171 deaths per 1,000 children (World Bank 2005a:28).⁸⁰ Undernourishment is yet another revealing indicator, with SSA recognized as the

⁷⁸ In contrast, throughout the rest of the developing world, the average daily income of those living on less than one dollar per day has risen from 72 US cents to 83 US cents (World Bank 2005a:4).

⁷⁹ South Asia is second to Sub-Saharan Africa in terms of infant mortality, but records just over 70 deaths per 1,000 births (World Bank 2005a:11).

⁸⁰ Although a separate case was made for South Africa's GNI per capita, in terms of infant mortality, the country has not scored as well. It is among the few African countries to see infant mortality rise between 1990 and 2003 (from 45 to 53) (World Bank 2005b:313). One additional point should be made in this context, although HIV/AIDS is the cause of nearly 2.5 million deaths in Sub-Saharan Africa, since 1990 (more than in any other developing region), it is malaria that is the "leading killer" in Africa, with nearly

developing region with the highest incidence as well as the only such region to see rates rise since 1990 (to well over 30 per cent of the population) (World Bank 2005a:5). In addition, although minor progress may be noted, Sub-Saharan Africa, together with South Asia, rank among those developing regions with the most limited access to improved sanitation facilities, with such access for just over one third of the population (World Bank 2005a:32; World Bank 2005b:317).

In accessing these and other economic and social development indicators against the Millennium Development Goals (MDG),⁸¹ Sub-Saharan Africa, in contrast to all other developing regions, appears to have the fewest number of countries that have already achieved the (MDG) poverty reduction target (viz. halving the proportion of people living on less than US\$1 dollar) (World Bank 2006a:3). Also noteworthy is the region of SSA's status with regard to the second MDG goal of ensuring primary school for all children by 2015; here, Sub-Saharan Africa records the greatest percentage of countries of all developing regions that are "seriously off track" in achieving the goal (World Bank 2006a:4-5). For the remaining six MDGs, SSA lags behind, including in its record with disease; malaria, HIV/AIDS, and tuberculosis are all on the rise rather than nearing the goal of halting the spread of such epidemics (World Bank 2006a:12-13).

Thus, relative and absolute poverty continue to undermine social and economic development on the continent (with notable exceptions across North Africa and in other pockets including parts of South Africa), despite significant efforts to the contrary. Although an in-depth evaluation of such poverty is outside the realm of this thesis, a basic understanding is crucial for two reasons, which represent a conundrum of sorts. On the one hand, the investment needs are huge.⁸² On the other hand, there is limited public funding including concessionary loans, and foreign, private investors are often wary to put their money in projects given the level of underdevelopment and associated risk.

a million people, mostly children, dying as a result of malaria *each year* in Sub-Saharan Africa (World Bank 2006a:12-13).

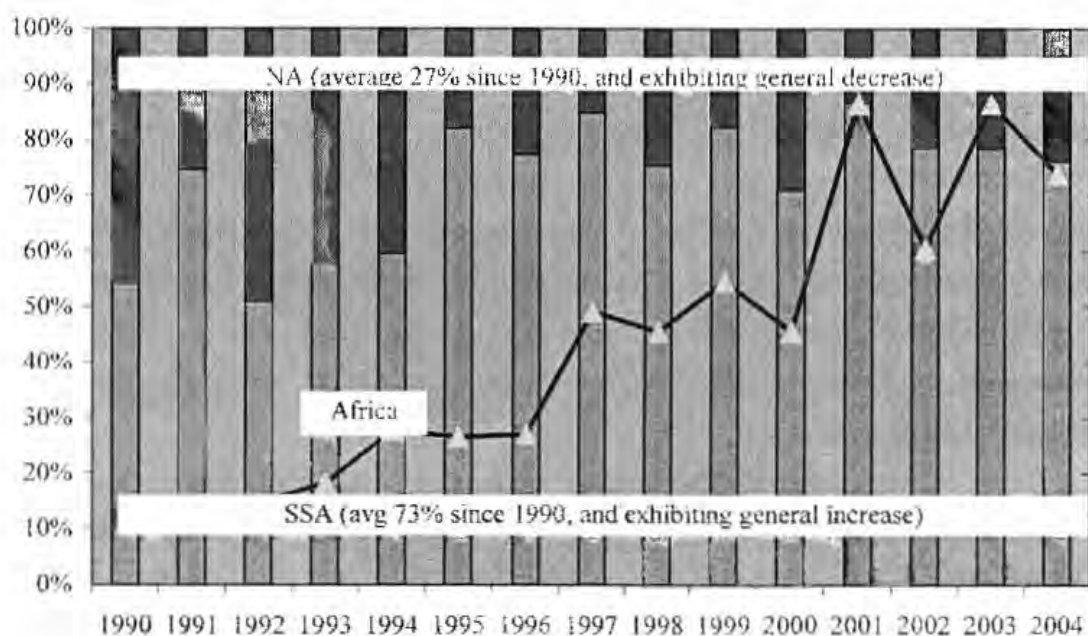
⁸¹ The MDGs, among the most frequently used metrics for charting economic and social development progress, outline eight goals to be achieved between 1990 and 2015 related to improvements in the following areas: poverty and hunger; universal primary education; gender equality and female empowerment; child mortality; maternal health; the spread of disease (HIV/Aids and malaria); environmental sustainability and enhancing a global partnership for development (United Nations 2005).

⁸² Estache puts the total expenditure across all infrastructure (electricity, telecommunications, roads, rail, water and sanitation) to be 9 per cent of GDP between 2005 and 2015 to meet the MDGs (Estache 2005:15). Fay and Yepes in estimating investment needs across infrastructure between 2005 and 2010 (not specifically with MDG targets in mind) came to a figure of US\$25.912 million or nearly 6 per cent of GDP (Fay and Yepes 2003:11).

3.1.2 FDI and the investment climate

What is the record of investment and why? At first glance, the Figure immediately below, which records African FDI, including a sustained increase for Sub-Saharan Africa, does not appear to square with the discussion above, namely foreign private investors are wary to tread on African soil.

Figure 3.2: Africa FDI, net inflow, balance of payments



Source: compiled by author, based on WDI (World Bank 2007e)

Although growth may be noted for the continent, it is important to recognize that FDI in Africa averages just 2 per cent of world totals for FDI between 1990 and 2004 (World Bank 2007e), despite the continent having 14 per cent of the world's population and 20 per cent of its land mass. The need for additional funding in virtually every sector—from health to electric power generation, as emphasized throughout sections 3.1.1—is acute, however, the investment climate keeps many would-be financiers at bay. Although a wide range of indicators seek to report on the investment climate in Africa, this section briefly profiles just one of the main indicators, below. Not only is coverage limited of many of the major indicators;⁸³ a detailed discussion of such facts is also beyond the scope of this thesis.

⁸³ Consider for example the Investment Climate Surveys as reported in WDI (World Bank 2006a:270-272). Senior managers are asked to report on the extent to which policy uncertainty, corruption, courts, crime, regulation and tax administration, finance, electricity and labour are considered major constraints to doing business. Only 13 countries throughout North Africa and Sub-Saharan Africa are included, and notably absent are Cote d'Ivoire, Ghana and Tunisia, which form part of this thesis' analysis.

3.1.3 Credit ratings

Among the most widespread metrics for judging a country's investment climate are international credit ratings, which assess the likelihood that an entity (sovereign, bank or corporate) will repay its foreign currency or local currency financial obligations in a timely manner. Both short and long-term, foreign currency and local currency ratings are internationally comparable assessments. The leading rating agencies, Moody's Investors Service, Standard & Poor's & Fitch, assign ratings when a bond is first issued, and that rating helps determine how high the bond's interest rate will be. If the agencies assign a high rating, that means there is little risk of default, so the issuer can obtain a lower interest rate.⁸⁴

It is the paucity of investment grade ratings that is the most striking feature of Africa. In North Africa, only Tunisia presently has an investment grade rating (Chambers 2007; *Sovereign Ratings Summary May 2* 2007). Throughout Sub-Saharan Africa, four countries have attained such ranking: Botswana, Mauritius, Namibia and South Africa. Morocco and Egypt, are, however, as noted above, considered to have relatively better investment climates and record just one notch below investment grade (BB+), followed by Lesotho and Nigeria (BB-) (*Nigeria launches power privatization sales pitch* 2006; Sheppard 2006; Sheppard, Klaudy et al. 2006; Chambers 2007; Sheppard R. per com 2007). In addition, 15 other Sub-Saharan African countries have received a speculative grade rating from at least one of the major rating agencies, namely: Benin, Burkina Faso, Cameroon, Cape Verde, The Gambia, Ghana, Kenya, Madagascar, Malawi, Mali, Mozambique, Rwanda, Senegal, Seychelles, and Uganda.

It should be noted that there is considerable progress to report on the ratings front, considering the fact that in the last two years, five Sub-Saharan African countries (Kenya, Namibia, Nigeria, Rwanda and the Seychelles) have all received ratings from the major agencies, for the first time. However, the persistent dearth of investment grade ratings is a signal for most investors not to approach. When they do approach, are the terms and conditions demanded beyond the reach of host country governments—a question to which this thesis will return to in evaluating the IPP outcomes including the role of the obsolescing bargain in its assessment of the three case studies.

⁸⁴ Each of the major agencies differs slightly in their ranking of long-term credit ratings (short-term are not provided below):

Moody's ratings: from highest to lowest. **Investment grade:** Aaa, Aa1, Aa2, Aa3, A1, A2, A3, Baa1, Baa2, Baa3. **Speculative grade:** Ba1, Ba2, Ba3, B1, B2, B3, Caa1, Caa2, Caa3, Ca, C1.

S&P's ratings: from highest to lowest. **Investment grade:** AAA, AA+, AA, AA-, A+, A, A-, BBB+, BBB, BBB-. **Speculative grade:** BB+, BB, BB-, B+, B, B-, CCC+, CCC, CCC-, CC, D.

Fitch's ratings (same as S&P): from highest to lowest. **Investment grade:** AAA, AA+, AA, AA-, A+, A, A-, BBB+, BBB, BBB-. **Speculative grade:** BB+, BB, BB-, B+, B, B-, CCC+, CCC, CCC-, CC, D.

3.2 African ESIs

3.2.1 Power generation and resource endowments

Despite the widespread poverty documented above, which is interlinked with FDI and the investment climate, the continent is endowed with significant natural resources, many of which fuel its electric power generation.⁸⁵ This section briefly sketches Africa's coal, natural gas, hydropower and oil resources, together with electric power production and consumption patterns.⁸⁶

Africa generated approximately 550 Terawatt hours (TWh) in 2005 or approximately 3 per cent of the world's total electricity generation (BP 2006:39), despite containing one fifth of the land mass and nearly 15 per cent of the population, as previously referenced. More than 40 per cent of this was generated in South Africa (BP 2006:39). The bulk of the remaining production was generated in North Africa.

It is coal that contributes most significantly to Africa's power generation or about 50 per cent of total electric generation—70 per cent for Sub-Saharan Africa and approximately 7 per cent across North Africa (World Bank 2005a:164; World Bank 2007e, compiled by author).⁸⁷ Explaining the disparity in usage is the fact that coal is found primarily in South Africa, which accounts for just over 5 per cent of total world coal reserves and the vast majority of coal found in both Africa and the Middle East, as of end-2005 (BP 2006:28).⁸⁸ ⁸⁹Nearly mirroring reserves, actual production of coal from Africa amounts to just under 5 per cent of world totals, again with South Africa accounting for 4.8 per cent of the total (BP 2006:30).⁹⁰

⁸⁵ It should be acknowledged that the resource curse or paradox of plenty as mapped by Terry Lynn Karl would not see poverty and resources at odds but rather a direct correlation between the two. For a detailed discussion see Karl and Gary (Karl and Gary 2004).

⁸⁶ Nuclear power production is minimal with South Africa's Koeberg station producing the only nuclear power on the continent; total consumption accounts for approximately 0.5 per cent of world nuclear consumption (United States Energy Information Agency 2005; BP 2006:33).

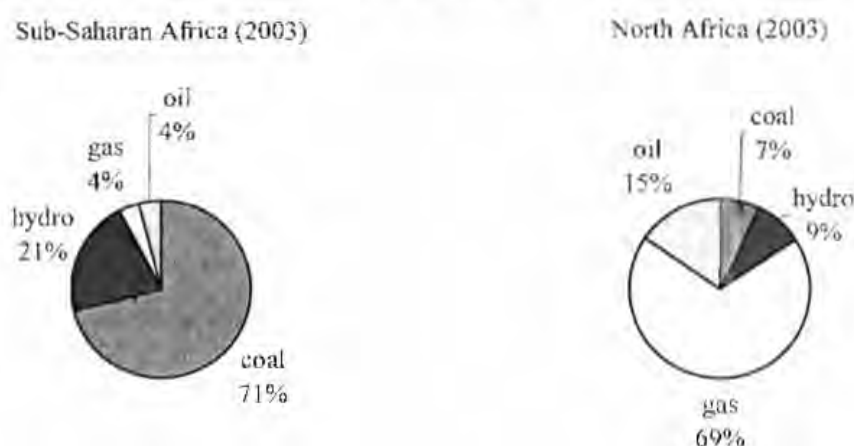
⁸⁷ An important exception to this breakdown in regional resources is the coal-fired Jorf Lasfar IPP, which increased Morocco's base load capacity by roughly 50 per cent. A more detailed discussion will be presented in section 3.4.1.

⁸⁸ As defined in BP's statistical review: this refers to proved reserves of coal (or other resources), namely "those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known deposits under existing economic and operating conditions," (BP 2006:28).

⁸⁹ Zimbabwe contains approximately 0.1 per cent of the world's total proven coal reserves and 'other Africa' approximately 0.1 per cent as well (BP 2006:28).

⁹⁰ As of 2002, South Africa was the world's third largest net coal exporter (United States Energy Information Agency 2005).

Figure 3.3: Contribution to electric generation by fuel source, Sub-Saharan Africa and North Africa



Source: compiled by author, based on WDI (2007e)

Natural gas ranks second in terms of electric power generation for the continent at approximately 25 per cent of total electricity generated; as with coal, a wide disparity may be seen with present usage, with natural gas accounting for about 70 per cent of total generation for North Africa, and just under 5 per cent for SSA (World Bank 2006a:164; World Bank 2007e, compiled by author). Since 1990, North Africa has witnessed growth of more than 200 per cent in terms of electricity generated by natural gas (World Bank 2006c). Natural gas reserves are concentrated primarily in North and West Africa, explaining the disparity in usage, namely: Nigeria (5.2 Trillion cubic feet, Tcf), Algeria (4.6 Tcf), Egypt (1.9 Tcf) and Libya (1.5 Tcf). Significant natural gas discoveries have, however, been made in Southern Africa, in Mozambique, Namibia and Angola, as well, with reserves of 4.5 Tcf, 2.2 Tcf and 2.0 Tcf, respectively.⁹¹ Altogether, African gas reserves amount to approximately 15 Tcf or about 8 per cent of total, world proven reserves (BP 2006:17; Energy Information Agency 2006; Energy Information Agency 2007). Natural gas production does not mimic the reserve profile exactly, with top producers in descending order: Algeria, Egypt, Nigeria and Libya, which together, with the rest of Africa combined, account for 6 per cent of the total of world gas production at the end of 2005 (BP 2006:19). Important to note that, in contrast to coal, the continent consumes less than half of what it produces (accounting for only 2.6 per cent of the world's natural gas consumption) led by consumption in Egypt, Algeria and South Africa, which imports from Mozambique (BP 2006:22). Much of the consumption profile could, however, change with the growth of natural gas-fired power plants in Nigeria as well as the development

⁹¹ Although comparatively less at 800 Billion cubic feet (Bcf), discoveries of natural gas are slowly changing the face of electric power generation in Tanzania, as will be discussed in Chapter 6. Also of significance in terms of natural gas development in Southern Africa is the Mozambique gas pipeline bringing gas from the Temane and Pande fields in Mozambique to Sasol (in South Africa) along a 537 mile long pipeline, since 2004.

of the West African Gas Pipeline Project (WAGP), which will transport Nigerian natural gas to Benin, Togo and Ghana, and which could eventually be extended to Cote d'Ivoire and Senegal. The Kudu Gas Project, which involves harnessing off-shore gas for a 800 MW power plant, and which like the WAGP has been in the planning stages for several decades, could also, bring more gas into the Southern African consumption profile. Smaller projects like Tanzania's Songo Songo Gas-to-Electricity project, which will be discussed in-depth in Chapter six, have been instrumental in changing the demand profiles of individual countries.

Hydropower is presently contributing nearly 20 per cent of electric generation for the continent—21 per cent in Sub-Saharan Africa and about 10 per cent in North Africa (World Bank 2005a:164; World Bank 2007e, compiled by author). It is estimated that 95 per cent of Africa's technical hydropower potential remains *unexploited* (Aardt 2006). The technically exploitable capability is estimated at 1888 TWh/year or approximately 13 per cent of the world's total technically exploitable capability (World Energy Council 2001). Installed capacity, at just over 20,000 MW, presently accounts for only about 3 per cent of total world installed capacity, despite the abundance of the resource (World Energy Council 2001), which points to low demand profile as well as the investment gap.⁹² In terms of hydropower that is presently exploited, it has been harnessed across Sub-Saharan Africa, with some of the largest installations (after Egypt) in: Democratic Republic of Congo, Mozambique, Nigeria, Zambia and Ghana (World Energy Council 2001). Furthermore, much of the technically exploitable capability cited above is located across these and other Sub-Saharan African states that lack natural gas, oil and coal resources. It should be noted that a number of the IPPs reviewed in detail in this thesis were developed with the immediate cause of alleviating electricity shortages due to drought (in largely hydro-based systems). Thus, reliance on hydropower goes a long way in explaining IPP outcomes across the continent. It should also be noted in this context that although the continent has not yet seen any large-scale hydro-powered IPPs, among the latest IPPs planned is Uganda's Bujagali, a 250 MW hydroelectric plant, with lead sponsor formerly the American-based AES and now Industrial Promotion Services (IPS), a subsidiary of Aga Khan's Fund for Economic Development (AKFED).

Finally, this discussion ends with oil, which amounts to about 8 per cent in terms of electricity generation across Africa. North Africa has seen electricity generated by oil drop since 1990 (by 20 per cent) as natural gas becomes increasingly ubiquitous. Meanwhile, although only amounting to 4 per cent of total generation in SSA, it has grown by more than 150 per cent since 1990 (World Bank 2006a:164; World Bank 2007e, compiled by author). Proven oil reserves, totaling approximately 115 thousand million barrels (as of the end of

⁹² Consumption also amounts to approximately 3 per cent of the world's total (BP 2006:35), with limited amounts of power generated via hydropower through North African linkages with the Middle East, through an interconnector with Jordan.

2005), are concentrated in North and West Africa, primarily in Libya (40 thousand million barrels) and Nigeria (35 thousand million barrels), followed by Algeria, Angola, Sudan and Egypt (BP 2006:2).⁹³ Actual production paints a similar picture, with the top producers presently, in descending order: Nigeria, Algeria, Libya, Angola and Egypt (BP 2006:2,4). All told, however, as of end-2005, Africa's proven reserves are only about 10 per cent of world proven reserves and production accounts for approximately 12 per cent of total world production, with the continent as a whole, consuming just 3.5 per cent of total world production, led by consumption in Egypt, South Africa and Algeria (BP 2006:4,6).⁹⁴

3.2.2 Installed capacity and consumption patterns

National electricity systems in African countries are small by international standards (with the exception of South Africa).⁹⁵ Installed capacity and per capita consumption are among the lowest across developing regions (World Bank 2007b). South Africa has a total nominal capacity of 42,000 MW,⁹⁶ followed by Egypt with 22,500 MW, then both Nigeria and Morocco with 5,000 MW (Egyptian Electricity Holding Company 2004; International Atomic Energy Agency 2005; Eskom 2006).⁹⁷ Thereafter countries taper off with Mali possessing a mere 280 MW and Burkina Faso, 120 MW (International Atomic Energy Agency 2005). One important, more recent development has been the addition of emergency also termed temporary power, namely units that are rented generally for 1-2 years during a power shortage. Although units are generally no larger than 100 MW, given the small base of installed capacity, emergency power, has come to play a significant role in African ESIs in the past decade.^{98 99}

⁹³ Other smaller producers include (in decreasing scale): Gabon, Republic of Congo (Brazzaville); Equatorial Guinea; Chad and Tunisia (BP 2006: 2).

⁹⁴ Michael Klare describes the increasing foreign interest in Africa's oil and gas resources as well as increased development and military aid as well as arm sales (Klare 2001:217-221). See also Karl and Gary (2004), as previously referenced.

⁹⁵ Interconnections provide the opportunity to supplement supply, however, they are not discussed in depth here as most private power investments have been for domestic markets to date.

⁹⁶ The case of South Africa is noteworthy in this context. Although the country has had significant excess capacity for two decades, RSA is presently facing a tight supply/demand balance, which impacts on the rest of the Southern African region, which is interconnected through the Southern African Power Pool (SAPP) and to which Eskom is the primary supplier of power. Ten Southern African countries are linked through SAPP, namely South Africa, Botswana, Swaziland, Mozambique, Lesotho, Namibia, Zimbabwe, Zambia, Angola and Democratic Republic of Congo (DRC). A further two countries, Malawi and Tanzania, are part of SAPP, but not linked.

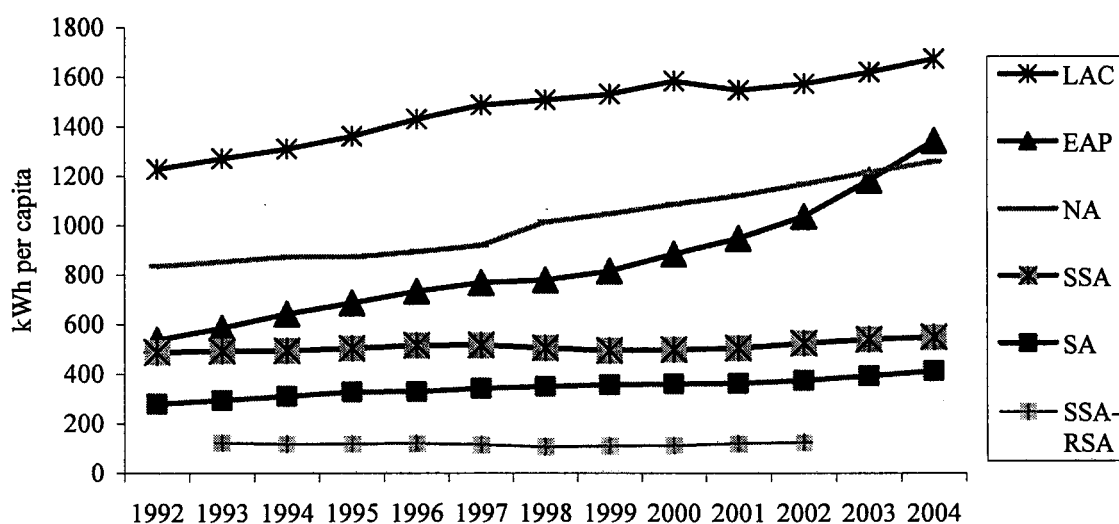
⁹⁷ Important to note, however, in the case of Nigeria, only about 3,000 MW of the approximately 5,000 MW installed are operational as 2007, due to age and maintenance of plants.

⁹⁸ Take for example Aggreko, one of the leading firms to provide such power in Africa, which after 10 years is active in providing power plants in about 10 countries across the continent, including about 40 per cent of Uganda's capacity as of 2006. It should be noted that if all forms of utility projects are considered, Aggreko's activity spans 21 countries across Africa (Aggreko 2006:21; Aitken S. per com 2007).

⁹⁹ Although such power has been particularly critical in staving off the effects of reduced hydro electric capacity as a result of drought, it is understandably more expensive due to the short duration of the contracts. In most countries, these extra costs are subsidized, with the cost of such subsidies in Uganda

Electricity consumption averages approximately 554 kWh per capita per year. This figure masks a wide disparity: 900 kWh for North Africa and 457 kWh for Sub-Saharan Africa, with the average for SSA falling to 124 kWh if South Africa is excluded (World Bank 2005b:245). For a global comparison, annual average per capita consumption across developing countries is 1,155 kWh (United Nations Development Programme 2006, table 22). This stands in sharp contrast to high income countries, which averaged 10,198 kWh (United Nations Development Programme 2006, table 22). Furthermore, if South Africa is excluded, SSA is the only region in which per capita consumption is actually falling. Due to its comparatively minute electricity markets, Africa has been easily passed over as a potential destination for IPP developers.

Figure 3.4 Electricity consumption per capita (kWh) 1992-2004



Source: compiled by author, based on World Bank (2005b; 2007g)

Note: Data for SSA-RSA only available between 1993 and 2002. Developing countries within the region of Europe and Central Asia (ECA) have been excluded from this graph with the average for ECA twice that of LAC.

In Sub-Saharan Africa, where 83 per cent of the African population lives, approximately one quarter of the population has access to electricity, and in some countries as little as 5 per cent of the population has access to electricity. There are presently 438 million people living in rural areas without electricity (as opposed to 109 million without electricity in urban areas) (International Energy Agency 2006:156). Rates in rural areas can be as low as 2 per cent, as seen in Tanzania (Marandu 2002). In Kenya, rural access rates are just 3.8 per cent (Kenya Ministry of Energy 2000). Electricity consumption is concentrated in urban areas among the

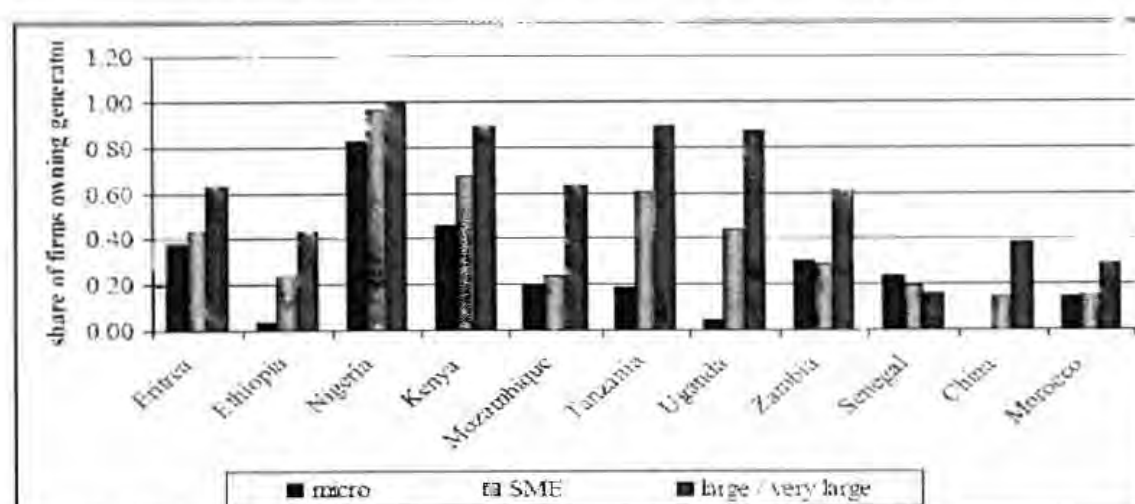
between 2005 and 2011 to be roughly estimated as equivalent to the total cost of the 250 MW Bujagali hydropower project (Uganda 2007:4).

middle and upper classes, larger business owners and the public sector (Estache 2005:33,40). While a quick survey may deem the 75 per cent unserved as 'latent demand', this demand is characterized by its poverty and often located great distances from any electricity infrastructure, i.e. it presents more of a public policy challenge than an investment opportunity.

3.2.3 Quality of supply and the ESI

Even for those who do have access, poor quality of supply is the rule, not the exception, in Sub-Saharan Africa (North Africa is not renowned for any such persistent and widespread poor quality).¹⁰⁰ Close to 100 per cent of large businesses operating in Nigeria, Africa's most populous country, have their own power supply due to the unreliability of electricity (Estache 2005:31).¹⁰¹ The figures total almost 90 per cent in Kenya, Tanzania and Uganda, and just over 60 per cent in Eritrea, Mozambique and Zambia (Estache 2005:31).

Figure 3.5: Percentage of businesses that rely on back-up generation



Source: Estache (2005:31)

Residential consumers and small businesses are less likely to own back-up generators and therefore suffer from poor quality supply most acutely. Interviews with stakeholders in Kenya confirmed the unreliability of the grid power and the high cost to industry. Kenyan manufacturers signaled that it was better to have expensive power than no power at all. In terms of transmission and distribution (T&D) losses, which is among the most frequently cited indicator of supply, there appears to be some disparity in the data. World Bank figures

¹⁰⁰ The Africa Infrastructure Country Diagnostic Study (AICD) is presently being undertaken and led by the World Bank, to benchmark performance, including the electricity sector, across the continent. AICD indicates that any such comprehensive performance data is currently unavailable (Africa Infrastructure Country Diagnostic Study 2007).

¹⁰¹ Furthermore, nearly 100 per cent of senior managers across industries, surveyed in an investment climate assessment, indicated that electricity is a major constraint to doing business in the country (World Bank 2006a:271)

record T&D losses of 12 per cent for SSA, in contrast to 16 per cent for Latin America, 26 per cent for South Asia, and an average of 24 per cent for all low income countries (2007b). Thus, the region of SSA would appear to be relatively better off. In contrast, in its 14 country review of East and Southern African states, SAD-ELEC presents data compiled by this author that reports T&D losses across countries (non-weighted) averaging 18 per cent (SAD-ELEC 2006:23). The prevalence of back-up generators as described above would also signal that reliability of supply is far from adequate.

Africa's quality of supply issues are a product of a several factors: system overload, decaying infrastructure, lack of investment (and in some cases, civil war and strife) which have spared neither civilians nor public works. Unlike those without access mentioned above, the businesses with back-up generators represent a more credible latent demand for potential IPP developers as the cost of self-generation exceeds US\$0.30/kWh (IFC per com 2005). A further impediment to investment is inadequate transmission infrastructure, both within and between countries, which further limits access to markets.

3.2.4 Organization of the ESI, tariffs and funding

How are Africa's ESIs structured and organized? As with ESIs across the globe, described in section 2.2, African ESIs throughout both North and Sub-Saharan Africa have traditionally been organized as vertically integrated monopolies, with ownership in the hands of the state (Nellis 2005:9-11). Over the last two decades, power sector reform has been propagated throughout the continent, and there are signs of movement toward corporatization and commercialization (including via management contracts). IPPs have been introduced in about 15 countries, and regulators have been established in approximately 20 countries, with efforts underway to set up such agencies in 12 more countries (Eberhard 2007:15).¹⁰² However, no African ESI has yet to be fully unbundled (vertically and horizontally), and nowhere is there evidence of either wholesale or retail competition (Besant-Jones 2006:22; SAD-ELEC 2006:9).^{103 104}

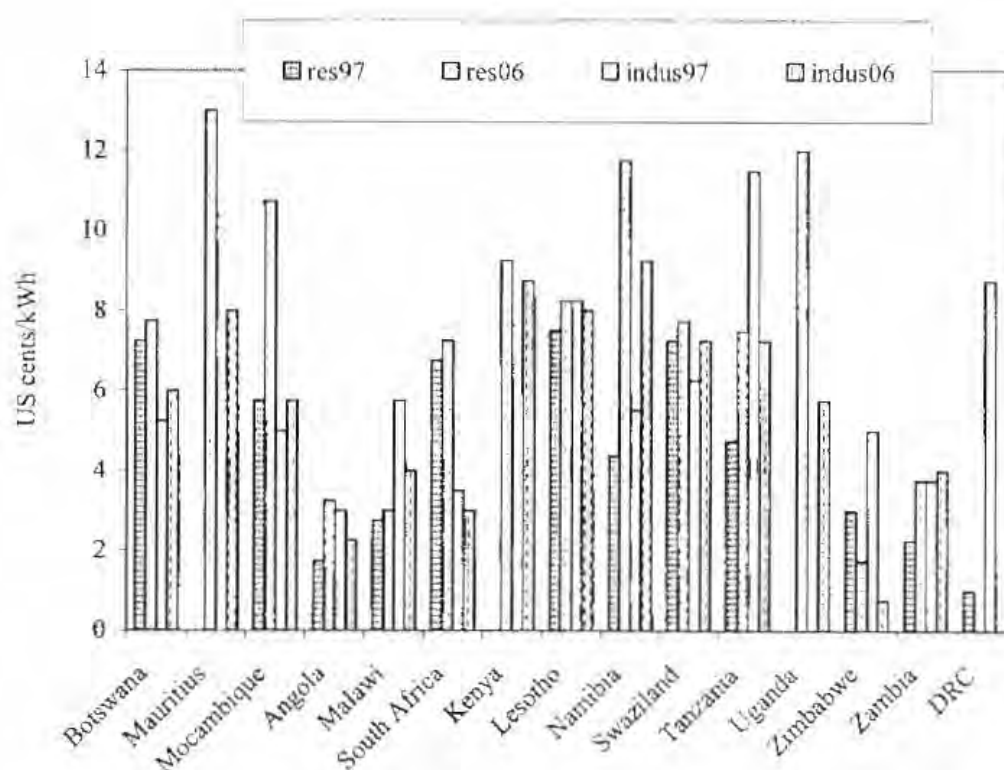
¹⁰² Many of the newly created regulators have, however, come under fire for what have been perceived as inconsistent and often arbitrary rulings, thereby increasing rather than decreasing overall sector risk, as will be treated in greater detail in section 7.3.2 (Eberhard 2007:1).

¹⁰³ As referenced in footnote 96, SAPP includes a small short-term energy market (also known as STEM) and a bilateral market. Volumes of electricity traded on STEM reached a high of 842 GWh in 2002 and since then have declined, recording a mere 178 GWh in 2005, attributed mainly to the failure of Mozambique and Zambia participating due to rehabilitation and maintenance projects (Southern African Power Pool 2006: 14). SAPP's bilateral contracts amounted to just over 10 TWh in 2002, and have been increasing steadily to 16 TWh in 2004 and 19 TWh in 2005 (Southern African Power Pool 2006:14-15).

¹⁰⁴ It should be noted, however, that evidence for partial unbundling is found in Kenya and Uganda, where generation has been separated from transmission and distribution (Besant-Jones 2006:22). Furthermore, in Namibia and South Africa, local government is involved in distribution, and in Nigeria, the Power Holding Company of Nigeria (PHCN) has been nominally unbundled, however, PHCN still maintains a coordinating role.

While there is a general trend toward commercialization of the industry, pressure to develop industry, poverty and socialist ideology have all helped to keep tariffs below cost (Nellis 2005:9-11). Comprehensive data is not readily available for the continent; instead included immediately below is a comparison of tariff data for residential and industrial customers (of 100 kilovolt ampere, kVa) from both Southern and East Africa from 2006 and 1997.

Figure 3.6: Residential and Industrial (100 kVa) tariffs 1997 & 2006 SSA, nominal values



Source: compiled by author, based on SAD-ELEC, (1997:10; 2006:19)

Notes: Average Nominal Selling Price - Domestic Customers. Utilities noted below.¹⁰⁵ Absent from the 1997 data are three countries: Kenya, Uganda and Mauritius. 1997 provides data for Zaire (defined as Democratic Republic of Congo (DRC) since 1997) which 2006 does not.

Several points are worth noting. First, with the long-run marginal cost (LRMC) of power in SSA estimated at between 6 and 8 US cents/kWh, several countries are well below cost, namely Angola, and DRC (for residential tariffs), South Africa (for industrial tariffs), Zambia

¹⁰⁵ Full utility names are as follows: BPC: Botswana Power Corporation; CEB: Central Electricity Board, Mauritius; EDM: Electricidade de Mozambique; ENE: Empresa Nacional de Electricidade, Angola; ESCOM: Electricity Supply Corporation of Malawi Ltd; Eskom: Eskom Holdings, South Africa; KPLC: Kenya Power and Lighting Company Ltd; LEC: Lesotho Electricity Corporation; NamPower: NamPower, Namibia; SEB: Swaziland Electricity Board; TANESCO: Tanzania Electricity Supply Company Ltd; UMEME: UMEME Limited, Uganda; ZEDC: Zimbabwe Electricity Distribution Company; ZESCO: ZESCO Limited, Zambia (SAD-ELEC 2006).

and Zimbabwe, with tariffs hovering between 2-4 US cents/kWh (United Nations Environment Programme and United Nations Economic Commission for Africa 2006:62). Second, since the 1990s and the inception of power sector reform, there has been an increase in virtually all residential tariffs, with increases in industrial tariffs noted in about half of the cases. Across the sample, the average tariff for 1997 was about 5 US cents/kWh for residential users and approximately 6 US cents/kWh for industrial users of 100 kVa, which is just on the border of LRMC. In 2006, these tariffs amounted to an average of 7.6 and 6 US cents/kWh for residential and industrial consumers, respectively (1997:10; 2006:19).¹⁰⁶

Although the evolution of tariffs may be inherently interesting, what is significant to this thesis, which does not purport to provide an exhaustive tariff review, is that at the start of reforms tariffs were often not covering even operational costs of the largely state-owned and operated utilities (World Bank 1993a:20; Komives, Foster et al. 2005:26). Many ESIs have operated largely on handouts. Concessionary lending, as documented in Chapter two, helped the sector limp along, but when soft loans were reduced in the early 1990s (or tied to power sector reform), Africa ESIs saw a new business model emerge, which will be documented below.

3.3 Private participation in infrastructure

Although there is little evidence for enactment of the standard model (despite it being held up as the 'standard' and part of policy statements in many developing countries), as discussed throughout Chapter two, there is nevertheless considerable evidence for private sector participation, including throughout Africa, prompted by the necessity of plugging the investment gap. This section briefly summarizes trends of private participation in infrastructure, across developing regions, focusing on IPP investments, in preparation for a larger discussion of IPPs in Africa in section 3.4.

The World Bank's PPI Database, among the most comprehensive sources for tracking private sector investment over the last two decades, provides a picture of such participation and investments (World Bank 2007c).¹⁰⁷ To contextualize within the broader framework of infrastructure reforms, private participation in energy (defined as electricity as well as natural gas, for which electricity represents 84 per cent of the actual total value of projects) has ranked second to telecommunications in terms of investment flows, followed by transportation and water. According to PPI, between 1990 and 2005, energy investments with private sector participation have occurred in 105 developing countries, through 1,307 projects, totalling US\$298,287 million, with Latin America and the Caribbean accounting for the largest number

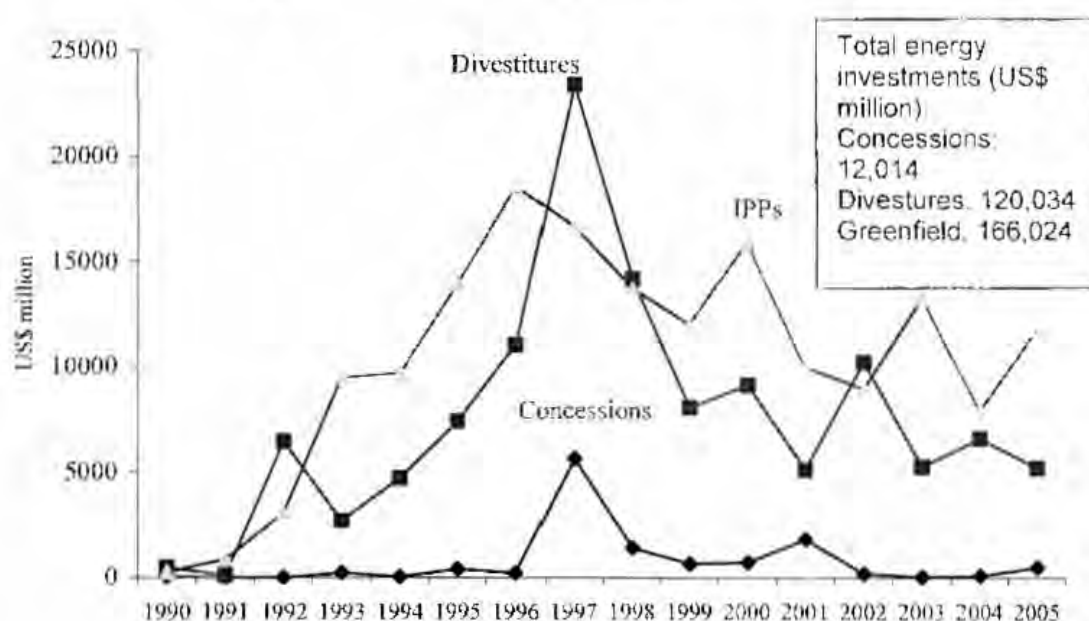
¹⁰⁶ Although not recorded in Figure 3.6 above, industrial users of 2500 kVA are reported in 2006 as paying on average just slightly less than the 100 kVA category at approximately 5 US cents/kWh

¹⁰⁷ More comprehensive reviews of results are reported in Kessides (2004) and Besant-Jones (2006: 30).

of projects (460) and the largest chunk of investment (US\$124,124 million) and Sub-Saharan Africa the least (with 69 projects valuing US\$7,171 million).¹⁰⁸

Depicted immediately below is a breakdown of projects by type of investment. Important to note is that although divestitures represented an unprecedented US\$23,370 million in 1997 (due mainly to several divestitures of utilities in Latin America), by far the most significant investment over the course of the past 15 years has been in greenfield investments, which largely represent investments in IPPs, for a total of US\$166,024 million. To put this figure in context, in the 1990s, IPPs represented about one tenth of private FDI in developing countries (Victor, Heller et al. 2004:2).

Figure 3.7: Private sector participation in energy



Source: author's compilation based on PPI database, accessed March 1, 2007

Note: In addition, Management and Lease Contracts (M&L) have lead to increased private sector participation; however, the volume is small at just 215 contracts over the 15 year period.

The year 1997, as alluded to in the Introduction, is cited as the peak year for private participation in electricity (Sader 1999:15; Covindassamy, Oda et al. 2005:1,4). Thereafter, the East Asia and Pacific financial crises followed by the Latin American financial crisis together with the collapse of Enron and its aftermath (namely a retreat of American and European-based investors back to their home markets) caused a sharp decline in private investment across developing regions (Covindassamy, Oda et al. 2005:6; Woodhouse 2006a:135). Thus, by the end of the decade, new investments in IPPs (to take one example of PPI) were fewer and

¹⁰⁸ Detailed analysis of PPI in electricity provided in Sader (1999), Jamusb (2002:3-12) and Kessides (2004:167-180).

further between. In 1997, over 90 IPPs reached financial closure, followed by less than 50 in 1998 and approximately 50 in each subsequent year (World Bank 2006c). In addition, approximately 30 of the 35 IPP contracts in the Philippines were renegotiated (albeit mutually renegotiated), and most contracts had also been renegotiated in Thailand, Malaysia and China. There was evidence of refusal to honour contracts in China and India, as well as cancellation of contracts in Indonesia and India (Woodhouse 2006a).

Despite widespread financial crises and several high profile contract cancellations, a recent study reports that remarkably few projects have actually undergone stress, defined as "electricity projects that have been terminated before their term; are under arbitration; are still ongoing, but declared unsatisfactory by either the investors, the host government, or the lenders; or went through a stress period, but were successfully worked out" (Covindassamy, Oda et al. 2005:19). Only 4 per cent of total PPI electricity projects are categorized as having experienced such stress. Furthermore, of all PPI electricity projects, IPPs tend to be the least susceptible—with only 3 per cent of IPPs noted as undergoing stress—which is credited to long-term contracts that are not subject to market fluctuations and the relative protection that projects enjoy from political machinations, as opposed to, for example, distribution projects (Covindassamy, Oda et al. 2005:61). Furthermore, also noteworthy, is the recent, albeit modest, increase in PPI electricity projects (Kerf and Izaguirre 2007:1).¹⁰⁹

Notwithstanding the rise and fall of PPI in electricity, PPI activity has been substantial. The question, however, is how substantial? As previously indicated, the value of the deals with private participation in energy between 1990-2005 was about US\$300 billion, with IPPs amounting to about 55% of this total (World Bank 2007c). Contrast this figure with the International Energy Agency's estimate for new investment needed to meet the projected increase in electricity demand and to replace old infrastructure between 2002 and 2030, in developing countries, namely US\$5.2 trillion (International Energy Agency 2004:191), i.e. the total new greenfield investment over the past fifteen years amounts to just three per cent of the total value for the next 30 years.¹¹⁰ While seemingly substantial, the investment flows in the larger scheme have actually been quite minimal.

¹⁰⁹ As noted in sections 2.7.2, the Stanford PESD IPP study concluded that 21 of 34 projects were renegotiated. The discrepancy in findings between the Stanford PESD IPP study and Covindassamy's Projects Under Stress may be explained by several factors. First, Covindassamy's work, based primarily on the PPI database, included planned projects, cancelled projects and projects under construction, whereas the Stanford PESD work considered only existing IPPs. Second, the PPI database also includes captive plants that occasionally sell power to the grid, which are outside the scope of the Stanford PESD work. Finally, although 21 of 34 projects were renegotiated, Stanford PESD records only 4 out of 34 projects as having had negative outcomes, which although still larger than Covindassamy's figure, are more comparable with the definition of stress employed in the World Bank study.

¹¹⁰ This projected investment figure does not assume any large increases in access levels in contrast to the figures provided in Estache, cited earlier (Estache 2005:15).

While the figures, cited above, may be intrinsically interesting, of critical importance is how and why these projects and investment flows translated into change and the nature of the change that occurred.

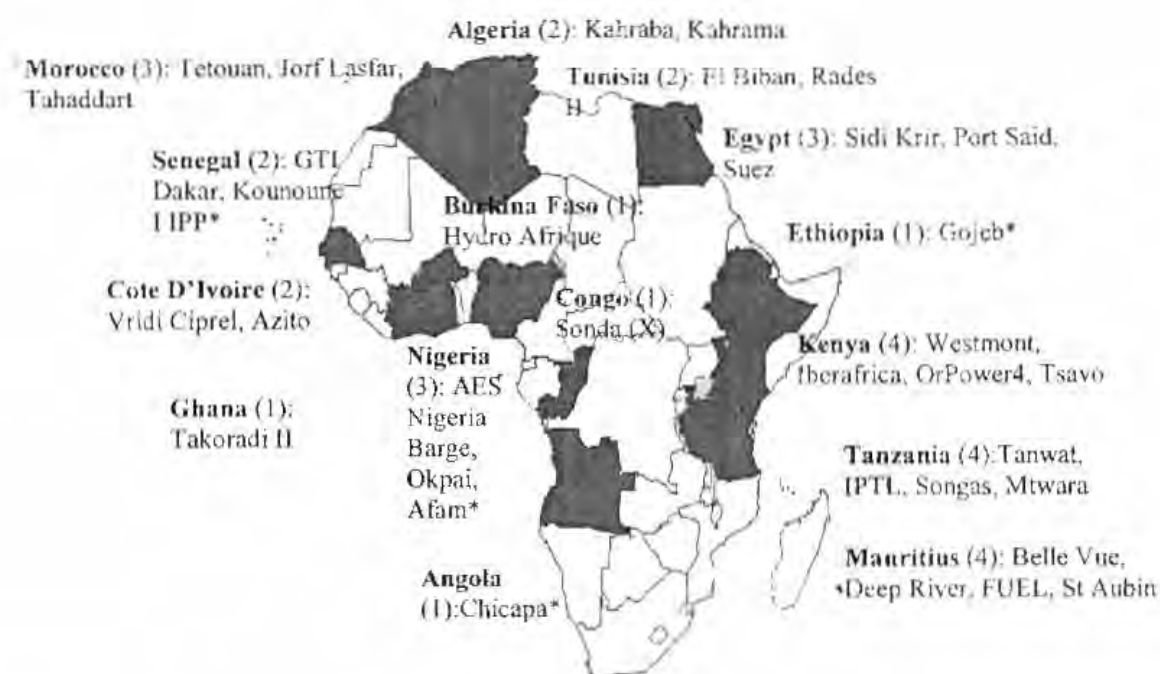
3.4 IPPs in Africa: an overview

Approximately 40 IPPs have been developed in Africa to date. With few exceptions, they represent only a fraction of total generation capacity and have mostly complemented incumbent state-owned utilities.¹¹¹ ¹¹² Nevertheless, IPPs have been an important source of new investment in the power sector in a dozen African countries, eight of these countries (Cote d'Ivoire, Egypt, Ghana, Kenya, Morocco, Nigeria, Tanzania and Tunisia) account for 80 per cent of installed IPP capacity.

¹¹¹ The International Energy Agency reports installed capacity for Africa at approximately 112,000 MW as of 2004; with IPP installed capacity roughly equal to 9,500 MW, IPPs are just less than 9 per cent of total installed capacity on the continent (International Energy Agency 2006:527). It should, however, be noted that the IEA total installed capacity figure appears to be inflated given data on systems (as presented in section 3.2.2); with no additional source providing comprehensive data on African installed capacity, the author has included the reference nonetheless.

¹¹² Exceptions are Cote d'Ivoire, Tanzania and Morocco where IPPs presently contribute more than half of all generation.

Figure 3.8: Greenfield IPPs in Africa¹¹³



Source: based on PPI database as well as author's compilation

Notes: (X) designates projects were cancelled; * designates projects are under construction; emergency power units are also not depicted.

Given these challenging conditions, how and why did IPPs take root at all? There was, as described in Chapter two, a general trend of power sector reform, driven in part by the DFIs, which play a particularly large role in Africa. There was also a growing sense within countries that the private sector could inject much needed cash and energy into the electricity sector. Thus, states solicited IPPs and, as will be discussed below, offered them terms and conditions to try to mitigate some of the risks outlined above. This section briefly explores the impetus for IPP development as well as how projects have unfolded across the different regions, with a special focus on the experiences of Egypt, Morocco, Tunisia, Kenya, Tanzania, Cote d'Ivoire, Ghana and Nigeria.¹¹⁴ A list of the IPPs in these countries is provided immediately below in Table 3.1.¹¹⁵

¹¹³ The map depicted above is based on the World Bank's PPI database and the author's compilation; several discrepancies with the PPI data should be noted. South Africa's Bethlehem, a 4 MW hydro facility is not included, due to the fact that it is only 4MW or 0.01 per cent of the country's installed capacity. Ghana's SIF Accra and Osagyefo Barge also known as Western Power, are also both excluded from the map as neither was an IPP per this thesis' definition (however, both will be mentioned briefly in the text). Two Nigerian plants included in PPI, Dadin and Ilorin, have also been excluded due to the fact that the former appears to be a state-sponsored project and the second project, contrary to PPI reports indicating that it is under construction, has not been finalized.

¹¹⁴ Although Mauritius has four IPPs (which, at approximately 200 MW combined, account for about 37 per cent of installed capacity and a little less than 25 per cent of production, as of end-2005), the country has not been included in this thesis' sample, primarily due to the idiosyncrasy of the contracts. The IPPs,

Table 3.1: African IPP sample, general project specifications

Country/ Project	Size (MW)	Cost (US\$ million)	Fuel/cycle	Contract type	Contract Yrs	Project tender -COD
Egypt						
Sidi Krir	683	413.9	Natgas/steam cycle	BOOT	20	1996-2002
Port Said	683	340	Natgas/steam cycle	BOOT	20	1998-2002
Suez	683	338	Natgas /steam cycle	BOOT	20	1998-2003
Morocco						
Jorf Lasfar	680+680 ¹¹⁶	1500 ¹¹⁷	Coal	BTO	30	1994-2000
CED	50	58.5 ¹¹⁸	Wind	BTO	19	1995-2000
Tabaddart	384	364.9	Natgas/combined cycle	BTO	20	1999-2005
Tunisia						
Rades II	471	260.7	Natgas /combined cycle	BOO	20	1997-2002
SEEB	27	30 ¹¹⁹	Natgas/open cycle	BOO	20	2000-2003
Kenya						
Westmont	46	35	Kerosene/gas condensate/gas turbine (barge-mounted)	BOO	7	1996-1997
Iberafrica	56	65	HFO/medium speed diesel engine	BOO	7, 15	1996-1997
OrPower4	13	54	Geothermal	BOO	20	1996-2000
Tsavo	75	85	HFO/medium speed diesel engine	BOO	20	1995-2001
Tanzania¹²⁰						
IPTL	100	120	HFO/ medium speed diesel engine	BOO	20	1997-1998
Songas	180	316	Natgas/open cycle	BOO	20	1994-2004
Mtwara	12	8.2	Natgas/ gas-fired reciprocating engine	BOO	2 ¹²¹	1994-2007
Cote d'Ivoire						
CIPREL	210	105.6 ¹²²	Natgas /open cycle	BOOT	19	1993-1995
Azito	330 ¹²³	233	Natgas/open cycle	BOOT	24	1996-2000
Ghana						
Takoradi II	220 ¹²⁴	110	Light crude oil/single cycle	BOOT	25	1998-2000

which are all cogeneration plants, provide power and steam to the country's sugar mills throughout the crop season, reducing their contribution to the state-owned utility by about 30 per cent. During this time, the shortfall in production is made up by seven Continuous Power Producers (CPPs), privately owned by the sugar mills. With installed capacity of 40 MW, roughly equal to the IPP shortfall, the CPPs also have long-term take or pay contracts with the state (Bergesen 2007; World Bank 2007c).

¹¹⁵ See Appendix A for additional data on IPPs.

¹¹⁶ The first 680 MW refer to an existing facility; the greenfield investment was an additional 680 MW.

¹¹⁷ Project costs included upgrade of the coal receiving facility and infrastructure for transporting coal to ONE's Mohamedia plant.

¹¹⁸ Project costs quoted in Euros at €45.7, converted to US\$ on August 24 2006 (€)=US\$1.28).

¹¹⁹ Project costs of SEEB, Songas (Tanzania) and Okpai (Nigeria) include the gas infrastructure.

¹²⁰ Tanzania's Tanwat (depicted on African IPP map), is a 2.5 MW facility, selling excess power into the grid and therefore is not included in this chart or in subsequent discussions of the thesis.

¹²¹ A long-term PPA for 20 years may be signed with TANESCO.

¹²² Investment cost €87.8m or 57.6 billion CFA, with the average 1994 conversion of US\$ to CFA, 545,100.

¹²³ The initial project concept included specifications to raise capacity to 420 MW.

Nigeria ¹²⁵						
AES Barge	270	240	Natgas /open cycle (barge-mounted)	BOO	20 (2 parts)	1999-2001
Okpai	450	462	Natgas/ combined cycle	BOO	20	2001-2005

Notes: COD: commercial operation date; natgas: natural gas; BTO: build, transfer, operate; HFO: heavy fuel oil

3.4.1 North Africa: Egypt, Morocco and Tunisia

A distinguishing feature of the North African experience is its investment climate which is significantly better than the rest of Sub-Saharan Africa (comparable with conditions in emerging economies in Latin America and South East Asia) and which inevitably impacted risk ratings, the cost of capital and IPP contract terms. Also of significance with the North African plants is that they were generally tendered under international competitive bids, and that plants were largely gas-fired with two important exceptions in Morocco.

Egypt: from 15 to 3¹²⁶

Unable to finance plants from its own coffers and faced with less interest by development finance institutions in the 1990s to provide finance for infrastructure, the Government of Egypt (GoE) turned to the private sector for new generation capacity. It passed the requisite legislation in 1996 to allow for private ownership of generation assets. The following year, new investments provisions, including sovereign guarantees, a five year corporate tax exemption, currency conversion, repatriation of profits, and protection against nationalization and expropriation, were also adopted to create a climate that would attract investors. The Egyptian Electricity Agency, later reorganized as Egyptian Electricity Holding Company (EEHC),¹²⁷ was given the mandate to drive the IPP process forward.

The IPP plan advertised to investors included a fleet of 15 projects, which would be phased in over several years. The first tender was for a 682.5 MW gas-fired steam cycle plant, under a 20 year Build Own Operate Transfer contract, with EEHC as the guaranteed off-taker, backed by the Central Bank of Egypt. Fuel was to be provided by the state-owned Egyptian

¹²⁴ The initial project concept included specifications to add a second phase of 110 MW and convert to combined cycle, however, lack of funding has limited the completion of this phase.

¹²⁵ In addition, as discussed in section 3.4.3 below, Nigeria expects to bring Afam V and VI online in 2007.

¹²⁶ The summary of Egypt's IPP experience presented here is based on field work conducted by author, with the major source being primary interviews with key stakeholders in the industry. As discussed in section 1.3.3, however, due to sensitivity of data, the names of stakeholders, who have been the primary source of data for this thesis, have largely been left out of the discussion, most stakeholders are only identified, if at all, by organizational affiliation in the text. In certain instances, however, where stakeholders have indicated their willingness, citations do include names and the designation of "personal correspondence".

¹²⁷ Egyptian Electricity Agency (EEA) was reorganized as the Egyptian Electricity Holding Company (EEHC) in 2000, through Law 164. The Egyptian Electricity Transmission Company (EETC) pays capacity charges to IPPs on behalf of EEHC.

gas firm (and the cost would be passed through to the Egyptian Electricity Transmission Company (EETC). Interest was high (fifty one firms applied for pre-qualification, 21 were initially pre-qualified, with 11 selected to receive the tender and 9 actually bid), and GoE ultimately negotiated among the lowest tariffs for developing country IPPs at 2.54 US cents/kWh. The second and third IPPs, 683 MW each and both gas-fired steam cycle, followed along nearly the same lines, with the major distinguishing feature of the latter two being that they were unable to secure domestic, US dollar denominated debt. Project finance, with limited recourse to parent companies, was arranged for all three deals.

With 12 IPPs outstanding and considerable interest among the present IPP sponsors, namely InterGen, Edison and EDF, Egypt met an unexpected development that would ultimately change the course of private generation in the sector. At the end of 2002, the Egyptian pound lost nearly half of its value, which had the effect of doubling the local price of IPP charges (which were denominated in US dollars). Despite pressure to change contract terms, the three IPPs (Sidi Krir, Port Said and Suez) remained unaffected. What did, however, change was the future builds. The 12 outstanding plants were cancelled, and the government, instead, with the help of development finance institutions, embarked on a publicly funded expansion. To date, the only new private power is being supplied by independent service providers (ISP), which offer both generation and distribution services to captive customers (primarily tourist resorts), but amount to only 1 per cent of installed capacity. A final development in Egypt's short IPP history is that, although not necessarily linked to the cancellation of the IPP programme, equity in all three IPPs has since changed hands, with InterGen and Edison selling their shares to Globeleq by mid-2005, and EDF selling its shares to Kuasa Power, a fully owned subsidiary of Tanjong Energy of Malaysia by early 2006. As Globeleq repositions itself as a developer of greenfield plants, it too has put its equity stake up for sale, with a conditional sale agreement completed in the second quarter of 2007 with a special purpose vehicle in which Tanjong Energy is also the leading shareholder.¹²⁸ Much remains to be seen, but Tanjong has indicated that if policy frameworks are established, the firm might even consider venturing into bilateral contracts (without government guarantees or any long-term PPA with EEHC), which along with the country's ISPs, might move it one step closer to achieving wholesale competition.

¹²⁸ It should be noted that, with the exception of Sub-Saharan Africa, Globeleq has put up its entire portfolio of assets for sale, as the firm seeks to reposition itself in developing new greenfield plants (rather than in taking over existing plant, as it did for the first few years since it was founded) (*Africa: Globeleq re-thinks asset sale after disappointing offers* 2007:7). Although a surprise to many outsiders, this development was always part of the firm's strategy, as Globeleq sought to plug the hole left by the exodus of many private investors following the downturn in the global power market in 2001-2002. While there has been much discussion of Globeleq's sale of its worldwide portfolio, a decision has since been made by the firm not to sell of any of its Sub-Saharan assets due to the fact that "indicative bids received did not meet the value placed on those businesses by Globeleq and its shareholders," (*Africa still just a flicker in the global M&A market* 2007; Globeleq per com 2007).

*Morocco: a local innovation*¹²⁹

Much of the same pressure, related to public funding constraints, seen in Egypt, was also at play in Morocco. The main difference in Morocco was the magnitude of the pressure: in the mid 1980's Morocco's public debt amounted to 110 per cent of GDP (reduced to 60 per cent by the mid-1990s).

In addition to helping to reduce the country's debt burden, the introduction of IPPs was expected to: free up funds for increased electricity access programmes, help meet growing electricity demand, contribute to diversification of fuel supply,¹³⁰ assist in the benchmarking of state-owned plants, and finally bring about both efficiency gains and a reduction in tariffs. Although these aims were common among procurers of IPP power, Morocco's actual procurement plan was radical. Through its first IPP, Jorf Lasfar, a 1360 MW coal-fired plant, Morocco increased its base load capacity by roughly 50 per cent.¹³¹

How Morocco achieved this revolution in its ESI through its first IPP may be seen as a result of a series of factors that will be explored in subsequent sections. At this stage, however, it is important to mention that the country, like Egypt, created a policy environment that clearly communicated its willingness to private investors. Legislation was passed to allow for concessions in the electricity sector in 1994 (albeit following a Build, Transfer, Operate (BTO) model to conform with existing Moroccan law). Equally important were the suite of investment incentives that were made available. As seen in Egypt, the project company was exempt from corporate tax for the first five years (followed by a 50 per cent reduction in years six through 10). Customs duties and value added tax (VAT) exemptions were also extended. A sovereign guarantee was provided for early termination and foreign exchange risk for Jorf Lasfar and was backed by a World Bank guarantee as well. An international competitive bid was commenced by the government in October of 1994 to build two additional units at Jorf Lasfar and operate the entire facility under a concessionary agreement for a period of 30 years. Three different consortia submitted proposals: (1) Asea Brown Boveri (ABB) and Consumer Michigan Services (CMS); (2) ADS and General Electric (GE); and (3) Alstom, with the first consortium ultimately selected.¹³²

¹²⁹ This section is based on Malgas, Gratwick and Eberhard (2007a).

¹³⁰ Significant headway had been made in terms of diversification since Morocco's independence in 1956 when the country relied on hydropower for nearly 90 per cent of its generation. At the inception of IPP development in the country, coal and oil were the dominant fuel, followed by hydropower.

¹³¹ Jorf Lasfar was a two part project: a brownfield (680 MW) and a greenfield (680 MW). Two other countries in Africa have had IPPs producing the majority of electricity. Cote d'Ivoire is also noteworthy for its capacity increase through IPP investments, with IPPs representing more than half of the country's installed capacity and production. Finally, although amounting to only one third of total installed capacity in Tanzania, Songas and IPTL, the country's two IPPs did, with recent droughts, contribute more than 50 per cent of total generation.

¹³² It is important to note, however, that both CMS and ABB have (since 2007) sold their equity to the Abu Dhabi National Energy Company, also known as TAQA.

Similar incentives would be extended for Morocco's second and third IPPs (excluding the World Bank guarantee), which like Jorf Lasfar were record setters. Compagnie Eolienne de Detroit (CED), the second IPP, was the first privately funded wind project in Africa, which would contribute 50 MW to the grid; Energie Electrique de Tahaddart (EET), the third IPP, was the country's first gas-fired combined cycled plant, at 384 MW, with debt provided entirely by domestic sources. The resulting cost of power is seen as attractive, as confirmed by public and private stakeholders, however the actual tariff for IPPs remains confidential, with the one exception of CED, at €3.9-5.9 cents per kWh (German Ministry for Economic Cooperation and Development Report 2002). Finally, it is worth noting that all three projects, like those in Egypt, were structured as limited recourse project finance deals.

Although the three IPPs are seen as success stories, untroubled by any macroeconomic shocks to date,¹³³ state involvement in the power sector remains (as originally envisaged by the government at the inception of the IPP programme). The government, through the state-owned utility (ONE), took a sizeable stake in the latest IPP Tahaddart (with nearly 50 per cent of the equity share) as it wanted to be involved in influencing the project and finance arrangements and thereby ensuring the best possible deal.¹³⁴ The next two wind farms, amounting to a total of about 400 MW, are expected to be owned and operated by the public sector. ONE is also launching a 472 MW hybrid power project, with 20 MW power by solar power and 452 by natural gas. Furthermore, feasibility studies are also being conducted by the state to explore the development of nuclear power. Amidst this state-led activity, there is, however, one IPP, for which competition is proving tough. Twenty firms have pre-qualified as of early 2007 to develop by 2011 a 1,320 MW coal-fired BOOT with a long-term (30 year) PPA with ONE. Thus Morocco's story is successful, but it does not clearly illustrate complete acceptance of private generation as the way forward. In fact, the success of the proposed new hybrid market, where large customers will choose their supplier and smaller customers will buy at a fixed tariff, depends on an optimal mix of IPPs and state-owned generation. Finally, it is worth noting that the drivers for IPPs are not as strong as at the beginning of the IPP programme: Morocco's external debt situation has ameliorated significantly and access rates have improved.

¹³³ Morocco has been untroubled by macroeconomic shock, however, it has also had a more proactive monetary policy to ward off the effects of macroeconomic shock with the dirham pegged to basket of currencies dominated by the Euro, which has had a stabilising effect on repayments due to the exchange rate remaining relatively stable since the first IPP was developed.

¹³⁴ Initially ONE was a minority stakeholder and only took 20 per cent of the equity. When one of the original sponsors, EDF, left, the state utility assumed a bigger stake (namely 48 per cent).

*Tunisia: investment successes and conundrums*¹³⁵

Of the three North African countries, Tunisia may be said to have had the best investment profile at the start of its IPP programme (with investment grade ratings with S&P, Moody's and Fitch), which had a clear impact on its ability to attract bids and cement favourable deals from the perspective of the host country. It is, however, also the only country in the North African pool of cases that, for reasons explained later, ran a selective bid (in addition to one international competitive bid) process.

With economic liberalization (rather than unavailability of public funds) the primary motivating force, Tunisia enacted the requisite legislation providing for private participation in generation in 1996. This paved the way for an ICB organized by the state utility, Société Tunisienne d'Electricité et du Gaz (STEG), in 1997 for a 471 MW gas-fired combined cycle plant. Seventeen firms responded to the RFP, from which the consortium of Public Service Enterprise Group (PSEG), Marubeni and Sithe was selected, for providing the lowest price per MW.¹³⁶ As seen in both Egypt and Morocco, incentives for the sponsor included a five year tax holiday. Also provided to sponsors of Rades II, the project company, was an exemption on VAT and customs duties for all imported equipment that could not be sourced locally prior to COD, as well as a government commitment for the completion of permit applications.

Similar to most of the Moroccan plants, investors in Rades II did not require a government guarantee, a fact which undoubtedly reflects on the sound investment climate. Also noteworthy was how Tunisia structured the capacity charges. STEG negotiated that payments be tied to a basket of currencies (roughly 60/40 split between Euros and US dollars) to mitigate the impact of future devaluations.¹³⁷ The payment negotiation was a direct response to earlier experiences in the 1980s, when the state utility financed another plant (Rades A) with loans denominated in Japanese Yen, which increased its value three-fold relative to the dinar and led to a major cash crunch for STEG. Neither the currency denomination nor the lack of guarantee biased the outcomes for Tunisia as the country was able to secure an investment cost for Rades II of US\$554 per kW installed (comparable to the price of IPPs in Egypt, despite the fact that the CCGT technology is more costly to procure).

Tunisia's second IPP has not been nearly as smooth in its development. Unlike Rades II, the second plant, also known as Société d'Electricité d'El Biban (SEEB) was an outgrowth of a government policy, enshrined in the 1999 Hydrocarbons law, to attract foreign companies to

¹³⁵ This section is based on Malgas, Gratwick and Eberhard (2007b), with, as indicated previously in section 1.3.2, the author of this thesis a co-author of the piece.

¹³⁶ Sithe exited the project during the development phase, and the shareholding was split 60/40 between PSEG and Marubeni.

¹³⁷ Apart from STEG's efforts at minimising foreign currency risks, the Central Bank of Tunisia has made preserving the value of the currency with respect to its major trading partners a major priority. The Tunisian dinar has devalued only by roughly an average of 3.5 per cent per year with respect to the US\$ over the 10 year period from 1993-2002, making it one of the most stable currencies on the continent of Africa.

explore oil and gas. Under this framework, the SEEB plant (a 27 MW open cycle gas-fired unit) was selectively tendered, as mentioned previously, in contrast to all other IPPs discussed thus far in North Africa, with CME serving as the initial project sponsor, together with Centurion Energy and Caterpillar Power Ventures. Project incentives included the five year tax holiday, now characteristic in the project pool, which facilitated in reducing the debt payback period to five years. Problems began to arise in 2004, a year after COD, when gas for the plant was contaminated, which had the effect of damaging SEEB's ejectors and hence adversely impacting the plant's performance. Approximately one year later, water entered the gas well, and gas could no longer be extracted. Captive to one gas well, SEEB has been out of operation from August 2005 until the present. During this time, no money has exchanged hands between STEG and SEEB.

The SEEB plant is not alone in its challenge to secure fuel quality and security of supply. In 2003, BG Group and the Government of Tunisia entered into a MoU for the development of the Barca project, a 500 MW combined cycle gas plant. One year later, however, negotiations with BG stopped due to concerns about the security of gas supply for the project. STEG has since been charged with developing the plant, albeit with a different fuel sourcing arrangement. A greater success story for IPPs lies with Tunisia's wind power developments; about 100 MW of privately constructed wind power is expected to come online in 2007, followed by another 200 MW between 2008 and 2011. Finally, although contingent on an interconnection with Europe, STEG has indicated that it will invite tenders for El Haouariam, a 1,200 MW CCGT IPP in 2007, with approximately two-thirds the capacity earmarked for Italy. Although Tunisia appears to be active in pursuing IPPs, like Morocco, state-led talks to develop nuclear power for electricity are also underway, with security of supply cited as the reasons behind both nuclear power and state involvement.

3.4.2 East Africa: Kenya and Tanzania

There are striking contrasts between the experiences in North Africa and those in East Africa, mostly related to the investment climate. But there are also notable similarities such as the push for fuel diversification and the host of investor incentives.

***Kenya: two different waves*¹³⁸**

Kenya stands out in this sample as the only country against which there was an aid embargo at the inception of IPPs. Therefore, while in other countries development agencies had signalled their unwillingness to fund infrastructure projects, in the case of Kenya there was a

¹³⁸ The summary of Kenya's IPP experience presented here is based on field work conducted by author, with the major source being primary interviews with key stakeholders in the industry. See section 1.3.3 for further explanation of referencing.

general no- funding policy across all sectors until the country enacted a series of political reforms. This embargo had the effect of sending the signal to potential investors that Kenya was *not* a favourable place to do business.

Nonetheless, investors did come, shortly after the passage in 1996 of legislation opening the sector to private firms, and Kenya represents among the earliest African countries to have IPPs reach commercial operation. Investors were offered custom exemptions and tax holidays until commissioning, similar to other FDI in Kenya, together with full repatriation of profits. In 1997, Westmont, a gas turbine plant burning kerosene and gas condensate, and Iberafrica, a medium speed diesel engine plant burning HFO (both under 50 MW) began providing power to the majority state-owned transmission and distribution utility, Kenya Power and Light Company (KPLC). Although less costly than the emergency power that the state would procure several years later to reduce the impact of drought, this first wave of IPP power did not come cheap.¹³⁹ The investment climate alone is not to blame, however, with selective tendering (rather than open international competitive bidding) followed and prices alleged to have been inflated by corruption as well.

Lessons from this first wave were quickly learned. The second round of IPPs (which comprise a 12 MW geothermal plant, OrPower4, and a 75 MW medium speed diesel engine plant, Tsavo) involved international competitive bidding, and contracts were ultimately approved by the newly established independent regulator. Kenya's Electricity Regulatory Board (ERB) was also instrumental in helping to reduce tariffs negotiated in a subsequent PPA between Iberafrica and KPLC. Although it remains unclear whether the same outcome could have been achieved had Kenya's regulator been sited within a ministry, the independent status of ERB has helped to make the body's actions ultimately less subject to controversy as the regulator appears to be at arms length from investor and host country government alike, i.e. both major stakeholders in the IPPs.

This shift between the first set of IPPs and the second, however, has not meant that it has been entirely smooth sailing. Compared to hydroelectric plants, owned and operated by Kenya Generating Company Limited (KenGen), the state-owned generator, IPPs appear expensive, and with persistent drought and increased reliance on IPPs, the second wave of IPPs have come under public pressure for capacity charge reductions as well. The International Finance Corporation (IFC), although part of the aid embargo during the 1990s, has since played a critical role in terms of helping the Tsavo project company, in which it holds equity, to resist pressure to renegotiate contract terms. Also of significance has been the role of the development-minded IPS and local partner KPLC Pension Fund in helping to mitigate local pressure for Tsavo and Iberafrica, respectively.

¹³⁹ Iberafrica, which has been benchmarked against IPPs in developing countries of similar size and technology proves to be among the most costly at US\$1,161 per kilowatt installed.

Kenya's generation future appears to have both more public and private generation investments in store: 100 MW in emergency power has been procured under a 12 month contract with Aggreko; a new 70 MW gas turbine will be built by KenGen, and a new diesel generator of 80 MW is expected from the private sector. Both the projects have, however, encountered delays for diverse reasons, including, in the case of the 80 MW IPP, the final award being disputed by one of the bidders in the ICB.

Tanzania: overcapacity and under-capacity¹⁴⁰

Although no aid embargo existed in Tanzania at the time of its first IPPs, the country was still suffering from a poor investment climate. Emerging from a command economy, there was little explicit protection against nationalization, the currency was not convertible, and firms were unable to repatriate profits.¹⁴¹ In the country cases summarized until now, there has been a repeated emphasis on the dwindling role of finance provided by DFIs at the inception of the IPP developments.¹⁴² In the case of Tanzania, however, a slightly different model is in evidence with the World Bank, Sida, and EIB playing an important role in facilitating these new investments, given the abovementioned conditions.¹⁴³

Private sector involvement was sought for the development of Tanzania's gas reserves together with a power expansion at Ubungu and gas sales to third parties in the early 1990s, on the heels of legislation opening up the sector to private firms. This project, known as Songo Songo gas-to-electricity, was advertised to 16 firms and ultimately undertaken by a consortium led by TransCanada. It was expected that the gas-fired open cycle 60 MW expansion would be up and running within less than a year, despite the hefty infrastructure development (not to mention financial support) required. By 1995, however, with work on Songo Songo outstanding, a second deal was struck by government for 100 MW of diesel engines, known as Independent Power Tanzania Limited (IPTL), under a 20 year PPA.

At the time, Tanzania could absorb power from one plant, but certainly not two. Why then was the second deal reached? The impetus for IPTL may be attributed to a host of factors, including alleged corruption. Paramount among these factors is poor power sector planning and coordination. What ensued in the aftermath of the IPTL deal was a lengthy attempt at

¹⁴⁰ The summary of Tanzania's IPP experience presented here is based on field work conducted by author, with the major source being primary interviews with key stakeholders in the industry. See section 1.3.3 for an explanation of referencing.

¹⁴¹ The following terms would, however, eventually be extended to investors in the power sector: a five year tax holiday, customs exemptions, full repatriation of profits, protection against nationalization and currency conversion via a pass-through to bulk purchasers of power in the following month.

¹⁴² Technical assistance was often still made available; and there are cases where lenders did syndicate loans, take equity; and even provide debt.

¹⁴³ Several small self-producers also sell power to TANESCO, including Tanwat (2.5 MW), Kiwira Coal Mine (6.0 MW)—which were the first two IPPs---and Kilombero Sugar (2.5 MW). They sell only small amounts of excess power, and thus are not treated within the scope of this thesis.

cancellation and renegotiation of this second plant as well as temporary postponement of Songo Songo, led by the World Bank. Thus by the end of the 1990s, rather than having two IPPs in operation, the country had none.

IPTL would eventually emerge in 2001 from an international arbitration settlement, at the World Bank's International Centre for Settlement of Investment Disputes, with nearly US\$25 million shaved off its investment costs, representing a reduction of about 15 per cent. By that time, demand in Tanzania had picked up and capacity from both IPTL and Songo Songo were needed. The two plants, which reached COD in 2002 and 2004, respectively, would soon help the country to avert load shedding, but at a steep cost, as seen in Kenya as well. In 2005, costs for the IPPs absorbed 69 per cent of TANESCO's, the state-owned utility, total revenue, while contributing 45 per cent of the total power generated. Of these, IPTL's charges weighed more heavily: the plant represented 37 per cent of total IPP generation but 62 per cent of total IPP charges. Although seemingly inconceivable, in 2006, IPP production amounted to 55 per cent of generation, but charges amounted to 96 per cent of TANESCO's revenues, due to a significant drop in TANESCO's revenues as well as increases in the price of HFO (Ghanadan and Eberhard 2007:33).

Presently the government is stepping in to help bail out the ailing utility. Plans for future IPPs include 200 MW from Kiwira Coal & Power, to be fuelled by indigenous coal, with units originally due online in December 2006, June 2007 and December 2007—however, with Kiwira unable to raise finance for the 135 kilometre (km) transmission line, the project is presently delayed. One hundred MW from Richmond Development Corporation, which had no prior experience in developing power project, slated for September 2006, was delayed as well, although 20 MW is finally up and running after the Government of Tanzania provided funds to transport generators.¹⁴⁴ Neither of these projects, nor developments related to the Mnazi Bay Gas to Electricity project (presently supplying 12MW) was competitively procured. Meanwhile, since the end of 2006, 40 MW of emergency power have been commissioned from a subsidiary of Alstom and another 40 MW from Aggreko.

3.4.3 West Africa: Cote d'Ivoire, Ghana and Nigeria¹⁴⁵

In West Africa, two of the countries included in this overview (Cote d'Ivoire and Nigeria) have experienced civil strife, however, with different impacts on their IPPs. Ghana has been free of civil strife, but plagued by persistent drought, and several parallels may be seen with Kenya and Tanzania, as described above.

¹⁴⁴ This project has since been sold to Dowans Holdings, based in the United Arab Emirates.

¹⁴⁵ As previously indicated, in section 1.3.2, the Nigeria material included in this thesis is based on an as yet unpublished survey of Nigerian IPPs, which was conducted by the author of this thesis in collaboration with researchers at the Centre for Energy Research and Development at Obafemi Awolowo University in Ile-Ife, Nigeria in 2006. Additional interviews have since been completed by the author of this thesis for 2007 data.

*Cote d'Ivoire*¹⁴⁶

The story of Cote d'Ivoire, where IPPs provide more than half of the country's generating capacity, is noteworthy for a number of reasons. Compagnie Ivoirienne de Production d'Electricité (CIPREL), a 210 MW open cycle plant fired by domestically produced natural gas, was among the first IPPs to come online in Africa. With major shares held by Saur Group and EDF, this IPP started producing power in 1994. At the time, Cote d'Ivoire's investment climate was considered among the best in the region, with GDP growth at 7.7 per cent per annum. This relatively favourable investment climate would help attract bids for the second IPP, Azito, during its international competitive bid in 1996.¹⁴⁷ Ultimately a consortium composed of Cinergy, ABB, IPS and the Commonwealth Development Corporation (CDC)¹⁴⁸ was selected to develop the plant, with the deal safeguarded by a sovereign guarantee (as well as a partial risk guarantee from the World Bank's International Development Association, IDA). In 2000, when Azito, a 330 MW gas-fired open cycle plant, came online, it represented the largest IPP in the West Africa (since surpassed by the Okpai plant in Nigeria). Both plants have been instrumental in helping the country to avert the consequences of drought in a largely hydro-denominated sector.

Within months of Azito's PPA being signed (and shortly before project completion), the country was subject to a political coup. Since 1999, lengthy periods of civil unrest have been punctuated only briefly by moments of peace.¹⁴⁹ During this time of civil unrest, revenues of the national utility, Compagnie Ivoirienne d'Electricite (CIE), have been reduced by approximately 15 per cent,¹⁵⁰ which has had a direct impact on the state's ability to invest in new, and much needed, electricity infrastructure. Although revenues have fallen, there has, however, been no impact on the IPPs—neither damage to the plants nor suspension of PPA payments has occurred.

¹⁴⁶ The material for this section is based on a forthcoming survey led by Malgas on Cote d'Ivoire's IPP experience (2007c). As in the case of the Morocco and Tunisia studies referenced above, the author of this thesis is a co-author of the work, together with Anton Eberhard.

¹⁴⁷ Also noteworthy is that, with the exception of Kenya's IPPs, CIPREL and Azito are the only projects in this survey that were not granted extended tax holidays, which may be due to a suite of different factors including the fact that the return on investment ultimately reflected the single largest investment incentive together with the fact that these were among the first IPPs with a set framework as of yet undeveloped.

¹⁴⁸ Most of CDC's equity shares in projects were replaced by Globeleq, which was spun off of the CDC Group in 2002 and was established to invest in power projects in Africa, the Americas and Asia. CDC also invested in Tanwat, Tanzania's first IPP, which has not been included in this analysis as it was largely a captive plant producing 2.5MW and only selling excess power to the grid. It should, however, be noted here that Globeleq remains entirely owned by CDC.

¹⁴⁹ As of 2007, peace appears to be here to stay, with a democratic election on the horizon (expected in 2007).

¹⁵⁰ The 15 per cent reduction in revenues are due to civil unrest, with electricity customers in the north encouraged to default on payments (and at the same time threatening CIE of serious consequences should power supply be interrupted) as a means to seek favour and bolster political support

In addition, the country has seen a significant currency devaluation. Although planned, the devaluation occurred just after the signing of the first PPA with CIPREL, which could have but ultimately did not impact on the US dollar denominated charges.

One of the ways that CIE has been able to honour its IPP payments, despite the drop in revenues and currency devaluation, is through additional foreign exchange gained by the export of power to Benin, Burkina Faso, Ghana, Mali and Togo. Thus, even amidst the civil unrest, Cote d'Ivoire has continued to define itself as a major power hub for the region.

New generation capacity is now presently needed, to meet domestic demand as well as Cote d'Ivoire's growing foreign market. As noted above, the state's coffers are not able to finance new investments due primarily to a drop in revenue during the period of civil unrest. Thus, the government¹⁵¹ has turned to owners of Azito and CIPREL to sponsor the next new large investment. As of mid-2007, no deals have been arranged, but several points are worth reporting. First the sponsors of the first two IPPs and potentially the next one are no longer exactly those of the mid-1990s, with EDF having sold its shares in CIPREL (amounting to approximately 35 per cent)¹⁵² to Saur Group together with all smaller investors (amounting to approximately 12 per cent). Globeleq, which assumed CDC's shares in 2002 and among the investors in Azito, considered selling its shares in the plant, in line with its new strategy of concentrating on greenfield investments in 2006, as previously mentioned (in footnote 128); however, a decision has since been taken to hold on to the asset (Globeleq per com 2007). In contrast to EDF's exit and Globeleq's attempted exit, IPS, has indicated its interest in developing the last phase of Azito. With Cote d'Ivoire's unprecedented past, it remains unclear what the next record-breaking development will be exactly.

*Ghana*¹⁵³

Although not affected by civil unrest, Ghana's IPP story is a turbulent one. The country has just one operating IPP, Takoradi II, but there have been several attempts to launch additional projects. While all attempts have come to nought, due to the fact that such failures inevitably impact on the investment climate and the perception by stakeholders, they will be discussed briefly below.

In 1998, amidst drought conditions, the Ghanaian National Petroleum Corporation (GNPC) spearheaded a project, which was intended to facilitate private participation in the ESI.

¹⁵¹ It should be noted that CIE has no mandate to contract new investment, which is undertaken by the government via the Ministry, due to the existing management contract. The utility entered into a concession contract in 1990 with the French firm Bouygues, which expired in 2005. A second contract has since been agreed upon until 2020. Although the Ministry has indicated that it intends drafting a plan for the way forward before the expiry of the current contract, there are no near-term plans to unbundle and/or privatize the sector.

¹⁵² EDF has however remained involved in CIPREL a technical management consulting capacity.

¹⁵³ The material for this section is based on a forthcoming survey led by Malgas on Ghana's IPP experience (Malgas, Gratwick et al. 2007d).

GNPC bought a 125 MW barge-mounted generator from Italy's Ansaldo Energy, as part of a plan to harness recently discovered off-shore gas reserves. ICB procedures were not followed and the project, which has come to be known as Osagyefo Barge has been shrouded in controversy. Although almost a decade has passed since the project was closed, not one kilowatt has been generated, and like Kenya's Westmont plant, it sits idle even as the country suffers from severe power cuts. The main stumbling block has been the fuel source: GNPC has been unable to convince either the Government of Ghana or any private investors to build the requisite gas infrastructure. Presently on the cards is a plan to bring the plant onshore to Effassu and tap into the West Africa Gas Pipeline, however, the site that has been earmarked for Osagyefo Barge is not connected to the pipeline. With no investors willing to fund a connection, prospects for the plant look bleak.

SIIF Accra, although initially billed as an emergency power project, with a 36 month contract with the government, was keen to establish a longer-term presence in the country. Developers, Cummins and Wartsila, thus expected to extend their contract after the third year, i.e. SIIF Accra appears to straddle the definition between emergency power and IPP. The 39 MW steam-cycle diesel generator was negotiated during the drought of 1998. After the contract had been signed and with construction underway, drought conditions reversed due to heavy rainfall, making SIIF Accra's promised power unnecessary. When the plant reached completion at the end of 2000, the firm began to submit invoices, reflecting the agreed capacity charges, to the government. No payments were made, however. Subsequently, the new government that came to power in January 2001 responded by insisting that SIIF Accra should have discontinued construction once it was evident that the hydrological conditions had reversed. SIIF in turn continued to demand payment. Reconciliation was attempted, but the parties were not able to agree to a settlement. Meanwhile, Cummins and Wartsila shipped the 39 MW unit to Benin where it has provided power. Subsequently, SIIF sought international arbitration. As of mid-2007, there has been no resolution reached by the parties.¹⁵⁴

There is, however, as mentioned at the outset, one standing, operating IPP (a 220 MW single cycle plant powered by light crude oil), which like those plants in Cote d'Ivoire and Tanzania has provided much needed power to Ghana's ESI. The plant was developed by CMS (90 per cent), with remaining equity held by Volta River Authority (VRA), the state utility.¹⁵⁵ Initially it was intended that the plant would be built in two phases, first 220 MW single cycle,

¹⁵⁴ There have, however, been a number of emergency power plants, which did successfully produce power--30 MW provided via an 18 month contract by Aggreko and 30 MW provided by Cummins for 24 months, starting from June and September 1998, respectively. As indicated in Chapter 1, detailed treatment of such plants is beyond the scope of this thesis.

¹⁵⁵ Apart from the one IPP, Ghana's ESI is dominated by VRA, which owns all of the hydro generation and one thermal plant (Takoradi I). VRA also maintains a monopoly over transmission and distribution with the exception of the northern areas of the country, where the Electricity Company of Ghana (ECG), also a publicly-owned company, provides transmission and distribution services.

followed by 110 MW combined (steam) cycle. One of the stumbling blocks in developing this second phase, as cited by investors, has been the lack of government guarantees (which were, however, granted in the first phase of Takoradi II). Government guarantees do not, however, to be forthcoming, and the government of Ghana has indicated that the EPC costs are too high. There is a possibility that the recent change in ownership, with CMS selling its shares in 2007 to TAQA, the Abu Dhabi National Energy Company, may help jumpstart this pending second phase.

Meanwhile, several other investors, including CENPower, have offered to provide up to 360 MW of gas-fired generation to the country, as well as a consortium of mining firms (AngloGold Ashanti, Newmont Mining, Golden Star Resources and Gold Fields), whose businesses have been seriously impacted by persistent power cuts. The mining consortium's 80 MW plant, which will feed power into the grid, is due online in July 2007 (*Ghana wobbles as power deficit bites economy* 2007).

Nigeria

Nigeria, the last country in this overview, is a fitting place to end the discussion as it is presently embarking on a full-scale overhaul of its power sector and therefore has the potential to learn the most from the previous countries' experiences profiled in this Chapter. The present plans for power sector reform are underway and involve vertical and horizontal unbundling and selling off all of the state's generation and distribution assets (six generation companies and eleven distribution companies), previously National Electric Power Authority (NEPA), which were reorganized under the Power Holding Company of Nigeria (PHCN) in 2005.

The recent flurry of activity is part of a longer history of reform, with legislation passed in 1998 allowing private participation in the generation sector. The first IPP, sponsored by Enron, emerged amidst the emergency power situation of 1999 when just over a third of the country's total capacity was in operation and load shedding was becoming increasingly widespread. Initially, stakeholders, namely Enron, NEPA and the Lagos State government agreed to a 90 MW barge-mounted diesel plant to be run on liquid fuel, which would then be followed by a permanent facility comprising a 560 MW plant, using open cycle gas turbines (OCGT), both under a common PPA. International competitive bidding practices were overlooked, and the deal was negotiated within months, with the expectation that the first plant would be on-stream by December 1999.

Due to public pressure, however, this initial deal was modified, and renegotiations would carry on for twelve months through 2000. Major objections were raised: the lack of transparent and competitive bidding; the type of fuel to be used, the fact that the plant would not be penalized for poor performance; that the project company would receive excessive contract termination payments; and that payments would bankrupt the state and national utilities.

Amidst the renegotiation, the original plan for the land-based 560 MW plant was shelved.¹⁵⁶ The major items to be renegotiated involved increasing the initial plant from 90 MW to 270 MW (9 units of 30 MW each) and changing the fuel from liquid fuel to natural gas, both of which had the effect of reducing the capacity charge to approximately US\$19.00/kW/month, and a final investment cost of US\$240 million. It was agreed that the capacity charge would be flat, for the 13.25 year duration of the contract, and that it would be indexed to the Consumer Price Index (CPI) of the OECD. Furthermore, capacity charges would be payable in dollars. There was to be no separate fuel supply agreement between the sponsor and the fuel supplier; instead, fuel was to be provided by NEPA/PHCN, which would contract it directly from the Nigerian Gas Company. As a final security measure, the PPA was to be backed by a sovereign guarantee. By the end of the renegotiations, ownership had changed hands, with AES acquiring 30 per cent of this facility in September 2000 and increasing its ownership to 95 per cent in December 2000. Yinka Folaṣiyo Power Limited (YFP), the local partner, purchased the remaining 5 per cent equity share of the plant.

Although agreement was reached and the plant has been online since 2001, PHCN has fallen behind in capacity payments (which are still publicly perceived to be high by the public). In addition, the government has yet to issue the tax exemption certificate, with causes linked to the perceived high capacity charges. Presently, negotiations are underway between sponsors and the regulator for further reductions to the capacity charges and agreements related to overall performance. Yet another recent stumbling block has been the fuel supply, with civil unrest in the Niger Delta leading to damage to the pipeline supplying AES Barge Limited.

The second IPP, like that in Tunisia, grew out of an additional reform mandate—namely for oil companies operating in Nigeria to harness previously stranded (in this case flared) gas for power. Investment incentives extended to sponsors are the same as for all upstream gas projects and include protection against nationalization and expropriation, and full repatriation of profits. Also known as Okpai, this 300 MW combined cycle plant is operated by Nigerian Agip Oil Company (NAOC), with majority ownership by Nigerian National Petroleum Corporation (60 per cent), followed by NAOC (20 per cent) and Phillips Oil Company (20 per cent).

The project financing was done entirely via the balance sheets of the joint venture partners. Construction costs of the plant also included complete gas facilities from its own oilfields and a new 330 kilovolt (kV) transmission line to evacuate power from the plant to the grid. Fuel risk was borne 100 per cent by the joint venture (JV) partners with the fuel cost embedded in the US\$0.022/kWh energy charge. The energy charge and the capacity charge (at approximately US\$13.00/kW-Month) are without adjustment other than for inflation using

¹⁵⁶ The plan for the 560 MW plant was shelved by Enron, but not abandoned, with development expected to follow after the first phase of the project.

OECD CPI. The plant has also come under fire for its higher than expected final investment costs. Parties are presently seeking to resolve the dispute directly (i.e. out of court) and meanwhile, the plant, which came on stream in 2005, is producing power but, due to the dispute, full payment is not being made by PHCN. Therefore, as originally agreed to in the PPA, the plant will not amortize after five years.¹⁵⁷

Although recently hailed as “a beautiful bride”, with the President’s economic advisor urging that “today not tomorrow” [is] the time to invest in Nigeria,”¹⁵⁸ the country has a muddled track record when it comes to IPPs. Still, an additional IPP is due online, in 2007 (Games 2006). Negotiations started in 2001 with Shell Petroleum for the third IPP, which involves a brownfield and greenfield investment namely: refurbishment of the existing 270 MW (Afam V) under an acquire operate own contract and the addition of 630MW (Afam VI) under a BOO arrangement. The project has, however, been delayed due to the civil unrest in the Niger Delta.¹⁵⁹ Furthermore, more IPPs may be in the pipeline, including possibly a coal-fired plant at Enugue or Benue State, a new hydro facilities at Mambilla or Zungeru as well as sale and expansion of the state-led Ibom project, particularly as the state aims to treble its capacity by the end of 2010 (from 5,198 MW at present to 15, 853 MW). Furthermore, four Nigerian firms (Farm Electric, Supertek, ICS and Eithope) have all been licensed to build power plants as of August 2006 with the expectation that power will start coming on line from these firms within the next four to five years, funded in part through domestic sources. With a regulator established since 2005, it is unclear the extent to which new and existing deals will be affected.

In May 2005, the Nigerian Electricity Regulatory Commission (NERC) was established; ostensibly independent from government with an independent source of funding, NERC has decision-making powers on key aspects of the ESI, such as approval of capacity expansion plans and oversight of quality of service. NERC is also charged with issuing licenses to companies operating in the sector and expected to regulate wholesale and retail electricity tariffs and prices. NERC’s interface with the IPPs is still being mapped and tested. In the meantime, a special purpose entity (SPE) has been created as an interim arrangement post-

¹⁵⁷ Interesting to note that there have been several IPPs sponsored by oil companies throughout South East Asia. Evidence gleaned by PESD researchers indicates that often such companies see IPPs as a means of marketing their primary product, namely oil, and have been more flexible in terms of negotiations related to power investments.

¹⁵⁸ In January 2006, Nigeria received its first ever rating from Fitch Ratings, a BB- (3 notches below investment grade), followed by a comparable rating from Standard & Poor’s (*Nigeria launches power privatization sales pitch* 2006).

¹⁵⁹ Although widely discussed in the media as IPPs, neither the 150 MW Omoku gas-fired, single cycle plant, nor the 180 MW Ibom gas-fired open cycle plant, both brought online in 2007 are IPPs following the definition of this thesis. The plants were not funded by PHCN, the state utility, but there was no private money per se as they were ‘independently’ financed by state governments (Rivers State Government and Akwa Ibom State Government). As of end-2006, however, Globeleq is “pursuing” investment in the Ibom project, which would include both investment in the existing capacity and an addition of up to 500 MW (Globeleq 2006:7).

unbundling with the mandate to take over some of NEPA/PHCN's liabilities, including the AES, Okpai and Afam contracts. This is intended to help ensure that unwarranted liabilities are not passed on to the transmission company.

It should be reiterated in closing that these brief country summaries (including of Cote d'Ivoire, Ghana, Morocco, Tunisia and Nigeria) have been provided to illustrate the range of IPP experiences across the continent. Although each one may offer invaluable insights into IPP developments, it is to an in-depth evaluation of Egypt that this thesis now turns, followed by one for Kenya and Tanzania. Each of these countries will, however, be revisited in Chapter seven.

Chapter 4

Egyptian IPPs

4.1 Introduction: the funding dilemma

The 1990s ushered in a major change for Egyptian infrastructure projects. Prior to this period, Egypt relied primarily on government funding together with soft loans from multi- and bi-lateral agencies to build and operate the country's roads, sewers and power plants.¹⁶⁰ By the beginning of the decade, however, according to stakeholders at Egypt's Ministry of Electricity and Energy (MoEE), a consensus was growing among donors, which advocated that the private sector, not the public sector, should take the lead in financing and operating infrastructure projects. What existed of limited public sector funding should primarily target social sectors, such as health and education. The World Bank, among Egypt's foreign funders, championed this new change in resource allocation, backing a general exit from infrastructure and reserving loans only if a commitment was demonstrated to reform the power sectors by introducing commercial practices, including by liberalizing prices, and competition. The arguments conveyed to Egypt were largely those spelled out in the 1993 World Bank Electricity policy document (as detailed in section 2.4.2) (Egyptian Electricity Holding Company per com 2005).¹⁶¹

With the loan conditions deemed politically unfeasible, however, and limited public funding available (from either Egypt's own funds or other donors) Egypt opted for private sector participation in its generation sector in the mid-1990s. Subsequently, between 1996 and 2003, the private sector contributed an addition of approximately 2,000 MW in power, in the form of three gas-fired steam generators, accounting for about 10 per cent of the country's installed capacity. Power purchase agreements with a duration of 20 years were signed with the state utility, and debt financing was provided by both local and foreign banks as well as institutional investors and multilateral development institutions.

The Egyptian IPP experience is interesting in a number of respects. While the original deals have held and the three gas-fired IPPs continue to provide reliable and affordable electricity, neither the original sponsors, nor the government, are keen to develop further IPPs along the same terms and conditions. Power provided by IPPs is still competitively priced by international standards (largely due to cheap state-supplied gas), but a major devaluation of the currency doubled the local cost of power purchases under the US dollar denominated contracts. In the aftermath of the devaluation and with concessionary funding now more abundant, the

¹⁶⁰ The public funding of infrastructure projects was the norm for Egypt until the 1990s, however the country did have experience with private sector funding. The Suez Canal was a build operate transfer (BOT) project, originating in the second part of the 19th century.

¹⁶¹ It should be noted, however, that no official document would be signed outlining any course of action or conditions, between the World Bank and Egypt.

Government of Egypt has charged the state-owned power utility with procuring further generation capacity, supported by DFIs. In the meantime, the original project sponsors in the three IPP projects have departed, and new equity partners have stepped in. Since 2004, the country has also launched its liquefied natural gas (LNG) industry, and after just two years Egypt ranked as the sixth largest LNG exporter in the world. With reserves less plentiful than originally expected, however, presently (mid-2007) a debate rages at the government level and ruling party level about how best to allocate natural gas reserves, which could ultimately impact on availability of gas for power as well as investment priorities. Interesting questions arise as to why and how the IPP investments have survived and what the future prospects are for private IPPs in Egypt and other African countries.

The first part of the Chapter provides a brief overview of the electricity sector including reforms undertaken to date related to IPPs. The second part involves an analysis of the development and investment outcomes (namely the extent to which the country and the investors benefited from the projects and whether such projects may be replicated in the future) as well as the major factors that led to such outcomes. Approximately two dozen interviews were conducted with about 20 stakeholders in January, February, August, November and December 2005 in Cairo, Washington D.C. and via teleconference in New York. Interviews were followed by email correspondence to clarify discussion points, with the last review of data conducted in May 2007, including with new stakeholders in Kuala Lumpur. Stakeholder interviews included present and former directors and managers at Al-Ahly for Development & Investment, Egyptian Centre for Economic Studies, Egyptian Electricity Holding Company, Egyptian Regulatory Authority (ERA), Electricite de France, Globelec, the International Finance Corporation, Poten & Partners, Tanjong Public Limited Company, the World Bank and local Egyptian banks. *Due to sensitivity of data, the names of stakeholders, who have been the primary source of data for this thesis, have largely been left out of the discussion; most stakeholders are only identified, if at all, by organizational affiliation in the text. As a result, much of the data, which forms the basis of this Chapter, is not cited. In certain instances, however, where stakeholders have indicated their willingness, citations do include names and the designation of "per com" for personal communication.*

4.2 Egypt's electricity sector: past and present

4.2.1 Sector reforms that made the IPPs, and some that didn't

Efforts to reform the Egyptian ESI originated as early as 1964, when the national utility was unbundled and eight distribution companies were formed. This arrangement remained until 1992, when the distribution companies were transferred from the Egyptian Electricity Authority (EEA), under the auspices of the Ministry of Electricity and Energy (MoEE), to the

Ministry of Public Enterprises, with the aim of further corporatizing the entities. By 1998, with little progress achieved, a decision was taken by the MoEE to transfer the entities back to the EEA, then re-bundle the distribution and generating entities into seven subsidiary, state monopolies (still under the control of the EEA)—an activity charged by some observers as counter to reform.

With the backdrop of the re-bundling of state utilities, privatisation efforts were slowly taking hold. In 1996, Law 100 was issued which specified: “local and foreign investors may be granted public utility concessions allowing them to build, operate and maintain power generation stations” (Republic of Egypt People's Assembly 1996). In 1997, a new investment law was introduced, which spelled out a number of investor incentives including government guarantees to secure projects.

At the time, the sector was averaging peak demand growth of 7.6 per cent per annum and increasingly dominated by natural gas as the primary fuel for power generation. In 1980 the share of gas amounted to only 20 per cent, with hydro accounting for 51 per cent, and oil making up the balance; by 1990, 40 per cent of the production mix was natural gas and only 24 per cent was hydro. As of 2004, natural gas dependence approached 80 per cent (Energy Information Agency 2004; World Bank 2006b).¹⁶²

Following the issuance of Law 100, IPP bids for a series of gas-fired steam generators were tendered and subsequently awarded in 1998 and 1999 (discussed in detail in section 4.2.3). At the same time, shares of the seven state monopolies were prepared to be offered on the Egyptian Stock Exchange, but with little interest by investors, this plan was never realized (Janet Matthews Information Services 2000).

The last major stage of reform was the reorganization of the EEA into the Egyptian Electricity Holding Company (EEHC) in 2000, through Law 164. Selected personnel at EEHC consider this change from EEA to EEHC to be corporatization, in part because EEHC is now expected to finance its own projects. The change also involved the unbundling of the seven vertically integrated subsidiaries and the subsequent separation of generation, transmission and distribution (*Egypt Restructures: may sell shares and assets but blows IPP program* 2001; Galal 2001). Each generation and distribution subsidiary was established as a separate corporate entity with its own board and external reporting. An internal pool was created for bidding in power, although ex-post price adjustments in the pool substantially undercut the potentially positive incentive effects.

¹⁶² It is anticipated that the gas share will continue to rise as oil-fired plants are converted to gas, for which proven reserves currently measure 69.5 trillion cubic feet (Tcf). However, as will be discussed in section 4.3.2, presently the allocation of reserves is being debated, which may in turn impact on electric generation. (Centre International d'Information sur le Gaz Naturel et tous Hydrocarbures Gazeux 2006; Schewe 2006; Egypt Staff 2007).

The corporatization of EEHC was intended as a step to prepare shares for privatisation, however, as of early 2007, this process has not yet begun (and it does not look likely to happen in the near future). Through EEHC, the government still controls close to 90 per cent of all generation capacity and maintains a monopoly over transmission and distribution. Cross-subsidization is rife. Finally, corporate governance regimes have not been strong and are characterized by significant involvement of the MoEE, who chairs the EEHC, in the operating decisions of the agency's subsidiaries.

It is important to note that the reforms described above took place in the absence of an independent regulator. Despite the issuance of a presidential decree to institute a regulator as early as 1997, no progress was made. A second such decree was issued in 2000. Thereafter, a board of directors was formed and a managing director appointed in May 2001. Staffing of ERA, with a grant from the United States Agency for International Development (USAID), began in January 2002.¹⁶³ Thus, the regulator came into force only after the IPP PPAs had been concluded and changes to EEA/EEHC had taken place as well, diverging from the steps of the standard model (as laid out in section 2.4.3), where the regulator is introduced before the introduction of IPPs.

ERA's founding document has, among other things, clear references to lawful competition (Egyptian Presidential Decree 2000: Article III). In keeping with one of its original mandates, therefore, ERA's main goal, in terms of future ESI reforms, is to create conditions where bilateral contracts between producer and consumer are the norm, and third party access to the transmission system is allowed. In an ideal arrangement, according to ERA, IPPs would compete in the market as well (unlike at present with 20 year PPAs with EEHC). ERA has recommended that 70 industrial/commercial users, which consume a significant portion of the total electricity in the country, source 20 per cent of their annual incremental increase in demand from bilateral contracts with the IPPs, thereby phasing in a new regime.¹⁶⁴ The details of such arrangements have not been spelled out to the public; needless to say, for such arrangements to be financeable, it would be necessary to craft agreements related to pricing, guarantees, damages and other key issues with extreme care, and contracts would be markedly different from those for existing IPPs.

To date, the Minister of Electricity and Energy has been reluctant to accept any such plan, arguing that neither the market nor the end user is sufficiently prepared for such an arrangement. While not official policy, it should, however, be noted that prices for large industrial consumers (those with transmission connections greater than 66 kV) have been

¹⁶³ As of 2007, the organization consisted of approximately 50 full-time staff. Its annual operating budget is estimated at approximately US\$900,000, with operating funds provided exclusively via licensing fees.

¹⁶⁴ One other possibility to introduce gradual sector reform, according to ERA, is that the natural gas utilities develop their own generation companies, which could then sell electricity to the large industrials together with the necessary gas feed. As with the previous proposition, details are not publicly available.

increasing, with the blessings of the MoEE. Furthermore, although also not an official policy, the government, via the MoEE, has been limiting electricity and gas supply to large industrial consumers, indicating that such consumers, which make up about 80 customers and approximately 23 per cent of current consumption, should negotiate/build their own supply. Some firms have responded by leaving, others by starting to put up their own plants and/or negotiating contracts with ISPs; still others are simply waiting for the official policy. This change is viewed as a transition to wholesale market competition. Meanwhile, official policy is in the making, with efforts to discuss a policy document slated for end-2007.

Furthermore, as of 2007, six ISPs have been licensed by ERA to provide generation and distribution services.¹⁶⁵ The ISPs identify their own customers, which are primarily in tourist areas along the Red Sea and Sinai, have no government guarantees, and also work independently of EEHC. Contracts are approximately one year in duration, with provision for renewal, i.e. no long-term contracts like Egypt's IPPs. Although the total installed capacity of the ISPs is only approximately 300 MW, or about 1 per cent of the country's installed capacity, the firms are expanding their activities, including most notably Global Energy, which was awarded a concession in 2006 to provide distribution services in Cairo, and could potentially pave the way for more private sector participation in the market.

EEHC cites the following reform goals for the future: the establishment of an independent transmission systems operator (TSO), which would promote wholesale competition; the commercialization of electricity distribution companies through re-engineering their business practices; and retail tariffs to cover costs by 2009. Work is underway on all of the three goals, with the establishment of the TSO slated for mid-2008 (originally for mid-2007). The TSO is expected to reside in EEHC for the first year of its operation, then be spun off from EEHC, but remain government owned. Furthermore, under consideration is a fund administered by EEHC directly to distribution companies to help eliminate cross subsidization and improve transparency of accounts. Finally, retail tariffs are already (slowly) on the rise, with annual increases of 5 per cent implemented since 2005, as will be discussed in greater detail below.

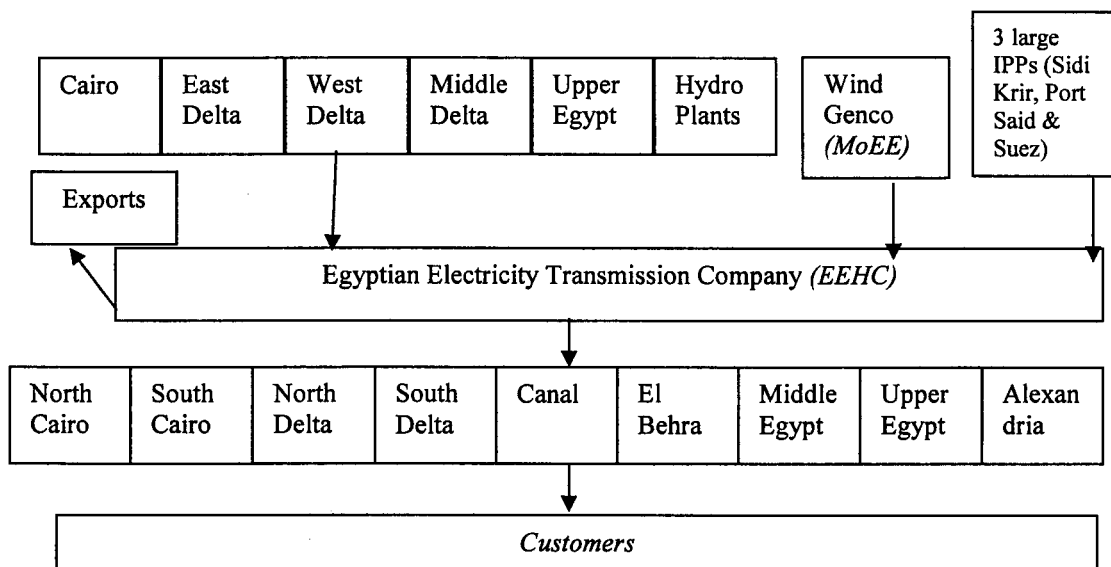
4.2.2 Snapshot of the current Egyptian ESI: results of the reforms

Figure 1 below is an outline of the current ESI. As of mid 2007, the Egyptian ESI consists of: six generation utilities; nine distribution utilities; and one transmission company. All of these entities are state-owned and fall under the direct management of the EEHC.

¹⁶⁵ The six ISP are as follows: Sendeian Company for Paper Industry, Alexandria Carbon Black, National Electricity Technology Company, Mirage Company, Om El Goreifat Company and Global Energy Company. Investors are primarily Egyptian and Jordanian, with one partnership currently under consideration, the Egyptian Chinese Joint Venture, which could introduce still more diversity into the supply mix.

In addition there exist: one wind generating company, which falls under the direction of the New Renewable Energy Authority within the MoEE; three independent power projects, one owned by Globeleq (since December 2004, but developed and operated by InterGen and Edison prior to that) and two by Kuasa Nusajaya, a wholly owned subsidiary of the privately-owned Malaysian firm Tanjong Energy (since March 2006, but developed and operated by EDF prior to that). As alluded to in section 3.4.1, in May 2007, Globeleq entered into a conditional share purchase agreement (SPA) with Pendekar Energy Limited (PEL), a joint venture between Tanjong Energy and the Saudi Arabian firm Al Jomaih for all shares in the Sidi Krir, with deal closure expected within six months time—a subject that will be further probed in section 4.3.3 below.¹⁶⁶ In addition, as discussed above, several ISPs involved in both generation and distribution primarily at tourist resorts provide power. As of 2000, 94 per cent of the Egyptian population had access to electricity.

Figure 4.1: Egypt Electricity Supply Industry



Note: not depicted in the Figure above are the 6 small private producers (ISP) that include generation and distribution.

Total installed capacity amounts to approximately 22,500 MW as of mid-2007, (with peak load demand of about 18,000 MW).¹⁶⁷ More than forty grid connected plants account for the

¹⁶⁶ This SPA includes all of Globeleq's Asian assets as well, namely six additional power plants in Bangladesh, Pakistan and Sri Lanka, which with Sidi Krir, total 1,810 MW in terms of their gross installed capacity (CIMB Investment Bank Berhad 2007:14). The deal is contingent on: the approval of Tanjong's shareholders (with an extraordinary general meeting to be convened by August 31, 2007); the agreement of the lenders in each of the seven plants; and, the agreement of the Bermuda Monetary Authority, due to the fact that Globeleq was incorporated in Bermuda, in 2003 (CIMB Investment Bank Berhad 2007:3).

¹⁶⁷ EEHC indicates that the use of installed capacity fluctuates significantly over the year, with capacities of the hydro plants (particularly High Dam, Aswan Dam 1 & 2 and Esna) decreasing during the period of minimum irrigation discharge; other plants are constrained during the hot summer months.

bulk of supply; furthermore approximately six off-grid plants, owned and operated by the ISPs, discussed above, with total installed capacity of 300 MW, make up the balance. Transmission and distribution losses across the network averaged 12 per cent in the period 1990-2001, with almost no variation.

EEHC has just concluded its Fast Track Power Generation Programme, which added an additional 4,500 MW of combined cycle gas plants at four different sites to the grid in between 2002 and 2007. The new builds are helping to absorb the approximate 7.5 per cent increase in demand per year during the same period. An additional 8,375 MW of capacity is in the works,¹⁶⁸ half of which are expected to be combined cycle and the other half steam, at 11 different sites for the period 2007-2012 when annual demand growth is projected at 6.6 per cent (Egyptian Electricity Holding Company 2003; Egyptian Electricity Holding Company 2004).

ERA has licensed all twenty-seven entities listed in Figure 4.1 (however licensing of the IPPs was concluded only in 2004 after project developers had ascertained that there would be no violation of their PPAs). ERA's mandate specifically states that the Agency must:

Regulate, supervise and control all matters related to the electric power activities [in generation, transmission, distribution and consumption] to ensure availability and continuity of supply so as to satisfy demand for the various aspects of usage at the most equitable prices, taking into consideration environmental protection, the interests of the electric power consumers, as well as the interest of the producers, transmitters and distributors. The Agency aims also at preparing for lawful competition in the field of electricity generation, transmission and distribution, and avoiding any monopolization within the Electric Utility (Egyptian Presidential Decree 2000, article II).

ERA's main limitations are two-fold: the Agency has no tariff setting power and it is chaired by the Minister of Electricity and Energy, which ultimately compromises the Agency's independence in regulating the sector. Should current tariffs be adjusted, the change would originate from the EEHC in consultation with the MoEE. ERA is, however, currently developing performance indicators that could serve as a proxy for tariff adjustments in the near term, with better performing utilities rewarded by reduced license fees.

Electricity tariffs for residential consumers in Egypt have been highly subsidised. According to figures published by EEHC and ERA (in 2006), average residential electricity tariffs amount to US\$0.037/kWh while average commercial rates are US\$0.066/kWh, based on (US\$1 = 5.74 Egypt pounds (LE), 5/31/07). Although on the decline, the persistent subsidy

¹⁶⁸ As of mid-2007, the roll-out of these new capacity additions appears to be on schedule.

throughout the past decade could help explain the strong growth in residential demand, which accounts for approximately half of all end-use consumption.

Between 1992 and 2004, there were no changes to the tariffs. Then in October 2004, the Cabinet of Ministers approved annual nominal tariff increases of approximately five per cent per annum for the next five years, with the aim of covering costs by 2009 (a stated EEHC reform goal, as previously mentioned). It should be noted that such increases were enacted in both 2005 and 2006. In 2010, a further evaluation is expected to ascertain whether additional adjustments are necessary.¹⁶⁹ This timeline may not, however, be moving sufficiently swiftly or convincingly. As part of a loan package for the El Tebbin gas-fired power station (discussed in the next section), the World Bank has included a technical assistance component, specifically to address financial performance and pricing structure in the sector (*Egypt: World Bank agrees El Tebbin support* 2006:3).

4.2.3 IPP frameworks, old and new

Egypt's first IPP framework, discussed in detail below, yielded three generation facilities for a total of 2,048 MW. Table 1 provides some project specifics. Despite a large currency devaluation, there have been no renegotiations of contract terms, but there has been high equity turnover.¹⁷⁰ As noted by numerous stakeholders, it is unlikely that the current framework will be replicated in the future should Egypt opt for additional IPPs. Instead a new framework is evolving to accommodate future developments.

¹⁶⁹ Assuming that the price of domestic gas used as fuel for the power plants remains under-priced, however, economic costs will remain only partially reflected. The exact level of under-pricing remains unknown by EEHC and other agencies as there is not one export price against which the domestic price can be compared.

¹⁷⁰ Other than the equity turnover, discussed in 4.2.2, the only changes that have occurred to date are related to the payment of local operating and maintenance costs, however, the PPAs contained a mechanism to escalate these costs and therefore the change does not constitute a renegotiation per se.

Table 4.1: IPP project specifics

Projects	Size (MW)	Cost (US\$ million) (D/E)	\$ per kWh	Fuel/ Cycle	Contract type	Contract Years	Project tender-Project operation
Sidi Krir	682.5	413.9 ¹⁷¹ (33/67)	606.45	Natural gas/Steam cycle	BOOT	20	1996-2002
Port Said	683.0	340.0 (25/75)	497.80	Natural gas/Steam cycle	BOOT	20	1998-2002
Suez	683.0	338.0 (25/75)	494.87	Natural gas/Steam cycle	BOOT	20	1998-2003
Total	2,048.5	1,091.9	-	-	-	-	-

Note: D/E, debt/equity ratio

The first IPP framework

The MoEE charged the EEA and later its successor, the EEHC, with leading the IPP process, albeit in constant consultation with MoEE. In 1994, the EEA began evaluating IPP agreements, including those of Pakistan, Turkey and Ghana. The World Bank and USAID's Submission and Evaluation of Proposals for Private Power Generation Projects in Developing Countries was scrutinized (World Bank and USAID 1994). Numerous seminars were conducted on the subject. In 1996, the EEA hired a consortium of USA-based consultants from Sargent & Lundy, Arthur Andersen and the law firm McDermott, Will and Emery to help manage the IPP process.¹⁷² During this early period, the utility was approached by Enron, which offered an unsolicited bid to develop the country's IPPs. The EEA refused the offer, opting instead to conduct a series of competitive, international bids, which involved four distinct phases, namely: pre-qualification and short-list selection; preparation of the request for proposals; evaluation and selection of the best bidder; and negotiation and execution of project agreements (Egyptian Electricity Authority 2000).

The 1997 Investment Law, mentioned in the previous section, provided developers with a number of additional key features: tax exemption (for the first five years), currency conversion, full repatriation of profits as well as protection against nationalization and expropriation (Egyptian Law No. 8/1997; Thomason 2004).

¹⁷¹ Previously project costs were estimated at US\$417.8, however, following negotiations with Egyptian customs authorities costs were reduced to US\$413.9.

¹⁷² It is worth noting that all three organizations, headquartered in the USA, have been involved in USA electricity reform programmes, albeit with some of the USA consulting work occurring at the same time rather than preceding the Egyptian reforms; therefore there is little evidence to support the fact that reform models that were used in the USA were subsequently exported abroad by consultants (Sargent & Lundy per com 2007) (McDermott Will and Emery 2007).

Table 4.2: Key IPP provisions, framework 1

Provision	Details
Sale and purchase of energy and capacity	20 year, US dollar denominated power purchase agreement exclusively between IPPs and EEHC Take-or-pay provisions for capacity factor of 65% (Sidi Krir), 70% (Port Said and Suez)
BOOT	IPPs to transfer plants to EEHC after 20 years in condition of "repair, cleanliness, and appearance which is consistent with Prudent Utility practices"
Capacity payments	From COD EEHC to make monthly capacity payments, equivalent to capacity purchase price multiplied by the dependable capacity
Energy payments	From COD EEHC to make monthly energy payments, equivalent to the energy purchase price multiplied by net electrical output
Dispute resolution	If parties unable to resolve disputes through mediation of experts, arbitration may be sought following UNCITRAL Arbitration rules, in Cairo, or if parties request, at the International Chamber of Commerce in Geneva
Additional	PPA will come into effect only if the Fuel Supply Agreement and the Central Bank Guarantee have each come into effect.
Government Guarantee	Sovereign guarantees signed between the Egyptian Central Bank and IPPs to cover EEHC payments including termination payment
Fuel Supply Agreement	Gas agreement signed between Gasco and IPPs

More than 50 firms (including project developers and equipment suppliers) applied to pre-qualify for Sidi Krir and a large number of firms were retained for the actual tender, which ensured that the competition was intense (*Second thoughts on BOT projects* 2001). Even without an independent regulator overseeing the tendering, Egypt was able to secure what has been characterised as among the lowest electricity prices for developing country IPPs at US\$0.0254 per kWh from InterGen and Edison, the project developers for the first IPP. This low tariff is partly attributable to the low gas price but also to the developers' perceptions about a favourable investment climate, no currency risk in the project and perceived long-term opportunities to build up a portfolio of generation assets (Egyptian Electricity Authority 2000; *Egyptian Gas Prices* 2005). Other significant features of the project included the large amount of local debt, albeit in dollar denominated terms.

Port Said and Suez, Egypt's second and third IPPs, were achieved along virtually the same lines, although somewhat faster, with the same set of conditions extended by the government. Tenders were comparable for two plants at approximately 683 MW each, which were awarded to EDF in 1999. The main differences between the two sets of projects (i.e. Sidi Krir on the one hand and Port Said and Suez on the other) apply to the financing arrangements, elaborated on in the next section.

After just two years of operation by InterGen and Edison and about the same by EDF (i.e. a 10th of the 20 year PPA), these firms opted to sell their assets. InterGen sold its 60 per cent share to Globelec in December 2004; Edison followed suit in May 2005. In August 2005, EDF entered into exclusive negotiations with Tanjong Public Limited Company, a Malaysian-based

gaming and power company. Negotiations were reported as concluded in December 2005; and as of March 2006 all EDF subsidiaries were sold to Kuasa Nusajayas (a subsidiary of Tanjong, for which the only assets are Port Said and Suez). Korea Electric Power Company (KEPCO) allegedly made an unsuccessful bid for the plants. Despite this notable equity turnover, there has been no change made to the PPAs to date.

The second IPP framework

A second IPP framework has been evolving since 2000 and currently includes a series of new provisions for IPPs, namely: all foreign currency must be obtained from abroad, rather than being sourced from domestic banks; local designers, contractors and manufacturers must contribute substantially to the execution of the projects; and local costs must be paid in local currency.¹⁷³ In addition, the bids that have both a larger equity-financing stake and a larger local investment component will be favoured.¹⁷⁴ Finally, project developers must bring their own customers with them, i.e. EEHC will not be the sole buyer.

These new provisions represent a significant change in developer risks, including financing and off-take arrangements, with the state recognising more fully the costs of the foreign private sector, especially those associated with the recent currency devaluation. To date, however, no new IPP projects have been undertaken within this second regime, other than the ISPs referenced in section 4.21.¹⁷⁵ From a developer perspective, the new terms may be viewed as less attractive than those applied to the initial three IPPs and, hence, the lack of interest is understandable.¹⁷⁶

The state (through the EEHC) has now once again taken the lead role in the expansion of the power system. All 4,500 MW required for the recently completed five year plan (2002-2007) has been financed by multilateral and bilateral development institutions. Approximately one third of project costs are domestic and the foreign portion is significantly less expensive than that negotiated through commercial banks as seen with the first round of IPPs. For the next five year plan (2007-2012), 50 per cent is already covered by concessionary funding including from the European Investment Bank, Arab Fund for Social & Economic Development, Kuwaiti Fund, African Development Bank, Islamic Development Bank, OPEC Fund and the World Bank, which as noted previously includes a technical assistance

¹⁷³ It is important to note in this context, however, that the first three IPPs utilised local labour, supported by only a small number of expatriate supervisors and maximised the use of local materials and equipment to minimize costs (selected correspondence with Globeleq, April 2005).

¹⁷⁴ There is no discussion, however, of the role of Egypt's local capital markets providing pound-denominated financing.

¹⁷⁵ As of mid-2007, one aluminum plant is presently considering whether to build a 500 MW coal plant and feed excess supply to the grid, but no plans have been formalized.

¹⁷⁶ The returns achieved under the first round of IPP projects were already fairly modest, and a requirement to increase the amount of equity financing will certainly not improve on this situation.

component for financial performance and pricing reform in the ESI, together with energy efficiency.¹⁷⁷

There is considerable doubt among existing IPP stakeholders that these publicly financed and operated plants will attain the same levels of efficiency as the IPPs, due to the fact that government plants often take longer to build and employ more staff. Even accounting for a reduction in efficiency, however, the soft loans may ultimately lead to cheaper power given the significantly cheaper financing. But is there sufficient public funding to meet all future power needs? The consensus among major stakeholders in the sector is that soft loans may actually be insufficient in the long-term, which begs the question of how the next IPP process will actually unfold, if at all.

4.3. A balance achieved?

The question raised repeatedly by this thesis is whether the sustainability of IPPs depends on development and investment outcomes remaining in balance. If returns to investors are inflated at the expense of host countries or if host countries win out at the expense of investors, will such IPP deals hold in the future? If balancing outcomes is the trick, what leads to such an equilibrium, particular given exogenous stresses?

In Egypt, IPPs are providing reliable power, which is deemed among the lowest electricity price for IPPs across developing regions (negotiated at approximately 2.54 US cents/kWh) (Egyptian Electricity Authority 2000:6). Development outcomes therefore appear to be positive. In terms of investment outcomes, returns on investments have been considered fair (although somewhat less than expected). However, none of the firms have grown their portfolios of assets.

What do these development and investment outcomes in turn mean for the sustainability of the projects? Will quality, affordable power continue to be supplied with equity being reasonably rewarded and debt serviced into the future? While there is no evidence for expropriation of assets (creeping or outright), all the original project sponsors have left. The introduction of new sponsors has not, however, led to any change in the PPAs, which would indicate that outcomes are indeed sustainable.

The following sections of this Chapter seek to unpack how such outcomes came about (by exploring exogenous stresses, followed by a detailed discussion of the elements that contributed to success, if at all, and how the sustainability of the projects discussed here relates

¹⁷⁷ In February 2006, the World Bank approved a US\$260 million loan for Egypt's El Tebbin gas-fired power project. The project involves a 700 MW power plant made up of two 350 MW steam turbines and boilers using natural gas as fuel, expected online in 2009/10. The loan will meet more than half the estimated US\$450 million cost of the project, with the majority of the remaining contribution coming from EEHC (*Egypt: World Bank agrees El Tebbin support* 2006).

to the broader ESI and power sector reform framework as well as the concept of obsolescing bargain.

4.4 Exogenous stresses

In the case of Egypt, neither drought nor civil unrest figured prominently in the country's IPP experience. Instead currency devaluation is considered the most significant exogenous shock. Since the signing of the PPAs for Sidi Krir, Port Said and Suez, the Egyptian pound has undergone a major devaluation, losing almost half of its value. At the time of PPA signing, 3.2 Egyptian pounds were equal to one US dollar. By May 2003, this had reached 6 pounds (to US\$1), hitting 6.3 pounds by November 2004. The Egyptian Electricity Transmission Company (EETC), which pays the capacity charges to the IPPs on behalf of EEHC, has therefore seen its monthly bill double in terms of Egyptian pound equivalency (compared to the dollar denominated capacity payments specified in the PPAs).

Pressure to float the Egyptian pound came as early as 1992 from the World Bank and IMF. Egypt resisted these pressures for more than a decade, even as the pound became increasingly overvalued. Reasons cited for the resistance include the lack of political will and capacity of the former Prime Minister (a new Prime Minister was appointed in July 2004). In the black market, there was a particularly steep rise (i.e. from 4.50 Egyptian pounds = US\$1 to 7.50 pounds = US\$1) in the year and a half before the float occurred, caused in part by 9/11 related recession. Finally, a decision to float the pound was made in end-January 2003, which sent shocks through the entire economy. It took almost another two years for government to adopt stabilizing measures, namely the introduction of the Interbank/US dollar market, which it did in December 2004 (World Bank 2003a:8).

While there is a general consensus among stakeholders involved with the IPPs—from the local banks to the project developers and utilities—that the pound was over-valued, the extent and speed of the devaluation surprised all. Furthermore, since the devaluation, the MoEE has backed away from its plans to develop a total of 15 IPPs, which it billed as Egypt's electricity future starting in 1998. This decision came as a particular surprise to project developers InterGen and EDF, which had their eyes set on more than one project.

Although future developments have been aborted, despite the turn in events, there has been no formal renegotiation of existing IPP contracts. InterGen/Globelec did indicate that EEHC approached Sidi Krir management when Egypt was experiencing an acute scarcity of dollars to request payment in pounds to the maximum extent feasible, but that due to its dollar denominated debt the firm was unable to acquiesce. Minor changes, since the devaluation, are

limited to partial payment of the local operating and maintenance component (both fixed and variable) in local currency, which amounts to approximately 4 per cent of the total charge.¹⁷⁸

With Sidi Krir, the change is an informal agreement between the project's general manager and EEHC.¹⁷⁹ With Port Said and Suez, the agreement went through negotiations with IFC, but EDF was given the option to return to US dollar payments at any time, i.e. it was not contractually bound. It should be noted that the sale to Kuasa and potential sale to PEL have not changed these agreements.

The devaluation has therefore had no appreciable effect, positively or negatively, on either InterGen/Globeleq or EDF's investments, due to the fact that all PPAs were US dollar denominated, as per the specifications of EEA's tenders.

4.5 Country level factors

An exploration into the country level factors that impacted on Egypt's IPP outcomes reads like a check list, with nearly all the items checked off. Evidence for a favourable investment climate? Yes. Proof for a clear policy framework? Yes. Signs of coherent power sector planning as well as ICB processes? Yes. Abundant low cost fuel apparent, together with the willingness of the government to share risks. The list then contains only two main items, which have not been deemed as contributing elements to success, which, along with the other factors will be discussed briefly below.

Foreign direct investment trends in Egypt were generally on the rise when investors negotiated their PPAs, as seen in Figure 4.2 below. The country had an investment grade rating (of BBB-) from major credit ratings as well (which would dip to one notch below investment grade in 2001).

¹⁷⁸ EEHC provided the following breakdown of the PPAs:

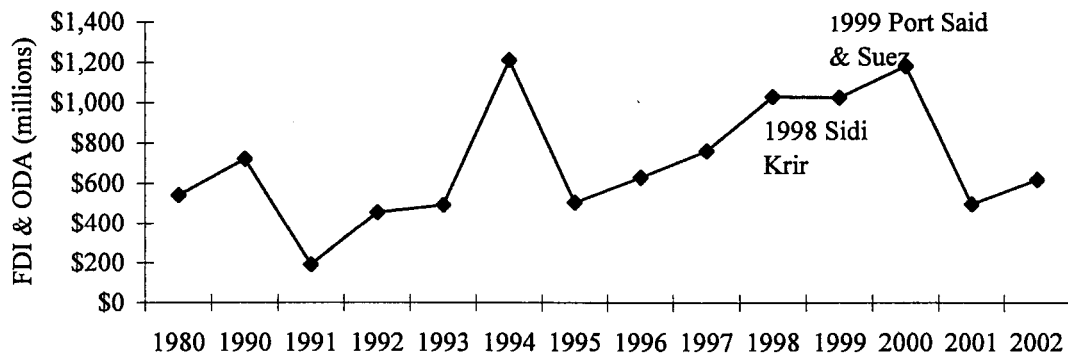
Capital reimbursement rate: 100 per cent US\$ denominated

Fixed O&M: domestic O&M: currently paid partially in local currency; foreign O&M: US\$ denominated

Variable O&M: domestic O&M: currently paid partially in local currency; foreign O&M: US\$ denominated

¹⁷⁹ It remains to be seen what will happen if and when the sale is finalized with PEL.

Figure: 4.2: Egyptian FDI 1980-2002



Source: World Bank (2006b)

Not only were InterGen, Edison and EDF following a larger trend in FDI, the companies also had prior experience in Egypt. For InterGen, its shareholders (Shell and Bechtel) were both operating in Egypt. Bechtel especially had long-term involvement with the MoEE and was keen to land a large IPP construction contract. EDF had a long-term relationship with Egypt in terms of providing technical assistance. CDC, from which Globeleq was spun off in 2002, also had prior experience in the country. Each of these existing networks and relationships helped facilitate the investment decisions made by the firms.

In addition to the above noted conditions, at the time of IPP tendering, Egypt's investment climate was generally perceived by investors as positive, which went a long way in attracting and cementing bids. Among the advantageous features cited by potential investors were: political stability (and a pro-western orientation), an active capital market, an efficient banking system, the degree to which contracts were enforced, the relative absence of corruption, the availability of a well educated and productive labour force at reasonable rates and a growing economy with a focus on increasing the private sector's role. Country risk was perceived to be minimal, and all investment conditions appeared to be primed for further improvement.¹⁸⁰

These factors, combined with the large natural gas discoveries, which will be discussed in greater detail below, offering a low cost fuel supply and a strong demand for electricity, made for particularly favourable investment prospects. Furthermore a total of 15 BOOT IPP developments were identified by the MoEE (all to be tendered via ICBs) including technology and site location as of 1998, which served to assure investors of the strong possibility for more than one project, thereby exploiting economies of scale.¹⁸¹

¹⁸⁰ It should be noted in its press release announcing the conditional sale agreement re: Sidi Krir in May 2007, Tanjong indicated similar favourable conditions, as well as the passage of a recent tax code that reduces corporate income tax rates by 50 per cent, and efforts to modernise treasury cash management and budget classification (CIMB Investment Bank Berhad 2007:6-7).

¹⁸¹ The plan to develop 15 IPPs has since been aborted, as discussed in section 3.4.1.

Of negligible importance to investors were the retail tariff subsidies. Allegedly, the absence of an independent regulator at the time also made no difference to investors as the projects were stand-alone deals with the Government of Egypt, with rights and obligations clearly set forth in the PPA and Central Bank Guarantee. Both InterGen and EDF have confirmed that such a guarantee was necessary for them to enter the market. Lastly, the re-bundling of EEA's distribution and generation entities did not feature in investors' concerns. In sum, the inherent risk posed by the electricity sector and its delayed reform programme, was offset by the positively perceived investment climate, clear policy and planning framework and abundance of natural gas.

4.5.1 Abundant low cost fuel: how long will it last?

Although it has already been acknowledged that abundant low cost fuel was among the key pieces that helped attract and cement deals, given recent developments, the discussion of fuel deserves further attention. It should be noted at the outset that the fuel charge accounts for approximately 40 per cent of the total capacity charge (assuming approximately 75 per cent capacity factor) and has been instrumental in keeping charges low. The fuel relationship is governed by an agreement between Gasco, the national gas company, and the IPPs. Fuel costs are denominated in US dollars and are compensated to the project sponsors via a formula stipulated in the PPA. They are not a direct pass-through to the utility, i.e. project sponsors pay Gasco and are subsequently reimbursed by EEHC.

The gas price that the generators¹⁸² pay appears to be non-economic (i.e. potential export prices are higher than those charged to the IPPs). The subsidy is roughly calculated as the average national selling price (of pipeline and LNG) minus the supply sector cost (which Gasco provides to all IPPs and EEHC own plants).

Important developments are happening in the natural gas industry, however, which may impact future IPPs and possibly the three existing projects. First, the price of gas has been increasing. The current domestic gas rate, as of May 2007, is US\$1.25 for 1,000 cubic feet (Mcf). The price is determined by Egypt's Minister of Petroleum; thus price changes involve a ministerial decree. Since IPP project inception, several such decrees have been issued. Between 2001 and March 2004, the price was \$US 0.643 per Mcf. Then between March 2004 and September 2004 the price was raised to US\$0.85 per Mcf. As of September 2004, it was raised a second time to US\$1 per Mcf, and most recently by 25 per cent to US\$1.25 per Mcf.

Presently this increase in gas prices is absorbed wholly by EEHC, due to the pass through nature of the energy charge from IPPs to the utility, and the lack of a pass through provision to the consumers. Going forward, however, with potentially increasing gas prices, will EEHC be

¹⁸² According to sources within EEHC as of February 2005, IPPs pay the same rate as EEHC's other plants.

able to absorb the full cost of gas? It is not inconceivable that existing IPPs could be pressured to adapt gas arrangements to provide for some greater level of flexibility, including moving away from a dollar denominated transaction.

Increases in the gas price are largely a product of the increasing demand for Egypt's gas—both from abroad and home. In terms of foreign demand, presently Egyptian gas is fuelling markets across North Africa, the Middle East and Europe with more developments on the horizon.

- *Jordan/pipeline*: In 2003, the first part of the 10 billion cubic metres (Bcm) a year Arab gas pipeline was put in service, running from El Arish in Egypt across the Gulf of Aqaba into Jordan. Jordan's Aqaba power station has been converted to burn Egyptian natural gas as of April 2004. The pipeline has also since been extended northward as far as Rehab (Jordan) and is presently supplying approximately 1 Bcm/year. All new generation in Jordan in the medium term is to be gas-fired, which will translate into even greater demand for Egyptian gas (*Egypt: Now Lebanon eyes interconnector* 2005:3; *Egypt: Jordan study sees greater linkages* 2006:3).
- *Europe/LNG*: As of 2006, Egypt ranked as the sixth largest LNG exporter in the world (after less than two years exporting LNG), a position it maintains in 2007 as well (Egypt Staff 2007). Egypt has two LNG facilities: Spanish Egyptian Gas Company (SEGAS) and Egyptian LNG (ELNG). SEGAS, a joint venture between Spain's Union Fenosa, Italy's ENI, the Egyptian Natural Gas Holding Company and Egyptian General Petroleum Corporation, is located at Damietta and has export capacity of 7.56 Bcm/year. ELNG is a joint venture among the above-noted government entities and Malaysia's Petronas and British Gas (BG), with capacity of approximately 10 Bcm/year. Egypt exported a total of 10.54 bcm of LNG in 2005 and is expected to reach full capacity of 17.2 Bcm in 2006 (Schewe 2006).
- *EJILLST/power*: The planned interconnector among Egypt, Jordan, Iraq, Lebanon, Libya, Syria, Turkey (EJILLST) may also demand greater Egyptian gas and power supplies (*Egypt: Jordan study sees greater linkages* 2006:3).

The country is also experiencing a sharp increase in domestic demand, most notably due to the growth of energy-intensive industries, largely for export, such as cement, which until recently have also benefited from the subsidy discussed above. This heightened demand led the government to issue a temporary moratorium on new industrial developments (which has since been removed) as a general allocation of gas is determined. Furthermore large industrial consumers (those with transmission connections in excess of 66 kV), amounting to

approximately 23 per cent of total national consumption, are seeing prices increase slowly; such consumers are being encouraged (albeit informally) to consider putting up their own power installations, as was previously mentioned in section 4.2.1. Although natural gas reserves are plentiful, they will not be able to sustain the forecasted activity of domestic electricity consumption, LNG export and industrial growth. A debate is presently raging at both the government level and the ruling party level about which sector should be the primary beneficiary and when. While 25 new cement factories and three new steel factories have (since the lifting of the moratorium) been licensed, pending are new LNG contracts as well as a plans to develop several aluminium smelters (England 2007). Meanwhile, under consideration by EEHC are the roles of nuclear power and wind energy. A new energy policy/strategy is expected by end-2007, which should lay down the natural gas allocation and the role of other energy sources.

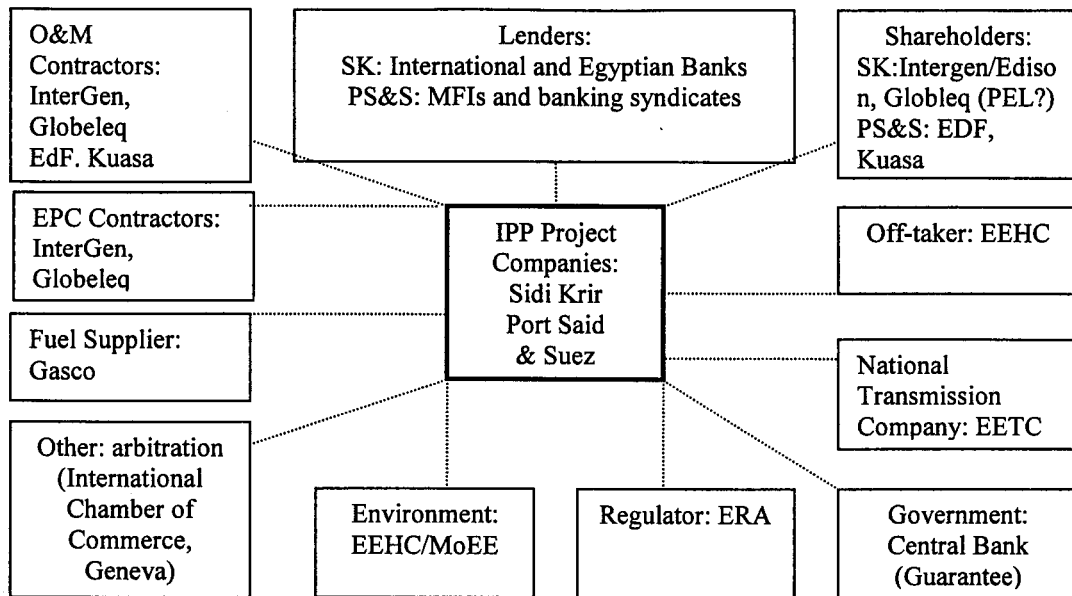
With this backdrop, it is possible that existing IPPs may see their own terms of trade under pressure. Furthermore, it is unlikely that any future IPPs will be able to negotiate similar terms. Sidi Krir, Port Said and Suez were all able to take advantage of the nascent gas market, which in just a few years has matured substantially.

4.6 Project level factors that impacted IPPs

The aforementioned currency devaluation and country level factors, including the now controversial nature of the Egypt's abundant low cost natural gas, go a long way in explaining both the development and investment outcomes for IPPs. These factors are not, however, the whole story. Of interest in this analysis is whether equity and debt arrangements were considerable favourable, as well as the extent to which revenue streams have been deemed both adequate and secure. What other risk management and mitigation measures safeguarded contracts (against the potential of the obsolescing bargain)? What about the technical performance of the three plants? Finally, how has strategic management and relationship building impacted on outcomes, if at all?

Figure 4.3 below highlights the range of different contractual relationships in which Egypt's IPPs entered, which will be taken up in the discussion of the myriad project level factors below.

Figure 4.3: Egyptian IPPs and associated contractual relationships



Notes: SK:Sidi Krir; PS&S: Port Said and Suez

4.6.1 Favourable equity arrangements

Engaging local partners has been used by many firms as a means to mitigate country risk, with India and China representing among the most striking examples (Woodhouse 2006a:193-198). Absent from any of the Egyptian IPPs, however, are local partners. Instead, these projects were developed exclusively by multinational firms: InterGen together with Edison (for Sidi Krir) and EDF (for Port Said and Suez).¹⁸³ Important to note in this context is that the firms had considerable prior experience in Egypt, which may have served to mitigate perceived country risk.

Multilateral development institutions were also absent, in terms of project equity, but figured prominently in EDF's debt for Port Said and Suez, which will be discussed in the subsequent section. This lack of equity involvement stands in strong contrast to other African IPP experiences, namely in Kenya and Tanzania where DFIs held significant equity shares in projects. Like local partners, this aspect does not appear to have strong explanatory power in terms of project outcomes, clearly reflecting a different investor perception of risks and rewards.

A more significant aspect that appears to be shaping outcomes is the firms' commitment to the country and equity turnover, which mimics activity in power sectors throughout the developing world. Although both InterGen and EDF had prior involvement in Egypt, both

¹⁸³ EDF cited that Egyptian investment was part of the firm's strategy toward global expansion which started in 1995-6. At this time, EDF focused on obtaining either existing companies or developing new assets. As part of its strategy, EDF made an initial bid, with Alstom, for Sidi Krir but was outbid by InterGen (selected interviews with EDF personnel, January 2005).

firms have since sold their shares. InterGen's reason for selling its interest in Sidi Krir to Globeleq in 2004 was based on the fact that its shareholders (Bechtel and Shell) made a strategic decision to move out of the business of owning and operating private power facilities. For Bechtel this meant moving back to its core business of designing, engineering and building plants, but not operating and maintaining them, and for Shell, it meant focusing on the petroleum exploration and production business.¹⁸⁴ Contrary to speculation from some stakeholders, the reason behind InterGen exiting Egypt was not a function of the firm prematurely recuperating its investment. Similarly, Edison has sold much of its global portfolio because of a decision to return to its core business in Italy. EDF also cites its plans of concentrating its investments in Europe.

With the Sidi Krir sale motivated by a strategic decision taken by InterGen's shareholders, the firm is known to have compromised its expected investment returns in the plant. The Sidi Krir sale has been estimated at US\$115 million (*Egypt: Tanjong unveils \$307m deal with EDF* 2005:3), against an original equity contribution of US\$139.2 million. Thus the change in equity turnover has directly affected investment outcomes. The opposite may be the case with EDF, with the firm selling its equity in the two plants for a reported US\$307 million, in contrast to the original equity contribution of US\$210, however, there was no signal by stakeholders that investment returns were more or less favourable than expected (*Egypt: Tanjong unveils \$307m deal with EDF* 2005:3).

While Shell, Bechtel, Edison and EDF's interest in owning emerging market IPPs has dwindled, along with many European and USA-based firms, Globeleq's mission revolves around power projects in emerging markets, with one important qualifier. Although the firm benefited from the early exit of investors like InterGen and Edison by buying assets at a discount, it has since decided to sell Sidi Krir, reflecting not a pull-out from developing markets, but rather a plan to focus on actual greenfield development. "Globeleq's business plan had contemplated since the beginning that we would acquire operating power assets during a period of time when those assets were available and undervalued by the market and, when market conditions shifted, devote more time and resources to greenfield development" (Globeleq per com 2007). Thus, according to the firm, the recent conditional sale to Pendekar Energy Limited is in keeping with its long-term strategy.

Tanjong, the lead shareholder in PEL, and the exclusive shareholder in Kuasa, is on the cusp of owning Sidi Krir, Port Said and Suez, all large-scale IPP generation in Egypt. There is, however, more to this tale, as previously indicated. With Globeleq putting all of its existing plants on the market (with the exception of those in Sub-Saharan Africa, which did not attract

¹⁸⁴ As of 2005, InterGen had developed 20 assets worldwide (since 1995). Of its original 20, the firm sold off 11, retaining just nine. Furthermore, in 2005, InterGen was sold by its then owners, affiliates of Bechtel Corporation and Shell Generating Limited, to affiliates of AIG Highstar Capital II, LP and The Ontario Teachers' Pension Plan.

favourable indicative bids), Tanjong Energy and Globeleq have agreed to a conditional sale for Sidi Krir as well as all of the firm's Asian assets, which include six additional plants, for a total of 1,810 MW, valued at approximately US\$493 million (Hin and Whitley 2007). When and if the sale is realized, Tanjong will have increased its generation portfolio by 25 per cent. What has motivated this privately owned firm, which is traded on the Kuala Lumpur Stock Exchange (and controlled by T. Ananda Krishnan) to undertake such a major acquisition? With excess generation capacity in Malaysia at approximately 40 per cent, there is little room for the energy arm of the firm to grow.¹⁸⁵ Thus seeking to position itself as a global provider of Operating and Maintenance (O&M) services and power generation assets, Tanjong Energy looked abroad and found EDF's offering followed by Globeleq's to match its aspirations. In 2005, it also bought up a generation and water desalination facility in the United Arab Emirates (*Egypt: Tanjong unveils \$307m deal with EDF* 2005:3).

PEL's minority shareholder, with 45 per cent, is of a slightly different breed. The Saudi Arabian-based Al Jomaih Automotive Company, a private limited company, incorporated in 1996, focuses on the wholesale and retail trading of vehicles and auto parts (CIMB Investment Bank Berhad 2007:4). It is the largest General Motors dealer in the Middle East. Unlike the original developers in Egypt's IPP, Al Jomaih has no previous experience in power generation. While Al Jomaih's foray into North African and Asian electric generation is the subject of speculation, the investments, all with long-term PPAs with state-owned utilities, represent a stable cash flow as well as an immediate income stream as plants are all in operation. Although Al Jomaih motives have yet to be fully unearthed, Tanjong has indicated that its partnering with Al Jomaih may be particularly useful as the firm contemplates further investments in the Kingdom (of Saudi Arabia).

It should be noted in closing that government stakeholders indicate that this equity turnover has not been disruptive and that plants continue to provide an important benchmark to the sector.

4.6.2 Favourable debt arrangements

Total project costs for each of the three IPP plants ranged between US\$338 and US\$413.9 million (at an average of US\$530/kW), with lower costs negotiated for each subsequent plant, to yield among the lowest IPP electricity prices in the developing world, as noted above. Of the US\$413.9 million in project costs for Sidi Krir, approximately US\$373 million accounted for the capital cost with about 10 per cent of the remaining being the financing costs of the plant (a similar breakdown is not available for EDF's IPPs).

¹⁸⁵For the fiscal year that ended 31 January 2007 (which does not reflect the PEL acquisition), Tanjong's power generation segment constituted: 74% of Tanjong's earnings per share and 69% of Tanjong's revenue (Tanjong Public Limited Company 2007:9-10).

The two sets of projects diverge in their financing, with the EDF plants more representative of IPP projects across Africa, given the involvement of a DFI. With project finance stipulated in the tender, equity accounted for about a third of the project costs: 33 per cent in Sidi Krir and approximately 28-29 per cent in Port Said and Suez.¹⁸⁶ Table 3 summarizes debt, both the source of the debt and the purpose to which it was allocated, where information is available, for the IPPs.

In the case of Sidi Krir, the majority of project debt, approximately 60 per cent, was sourced from local Egyptian banks, but denominated in US dollars; the remainder came from a suite of international banks, with no DFI involvement.

¹⁸⁶ It should be noted that this level of equity participation is quite conservative (with more aggressive examples of only 25 per cent or 20 per cent equity seen in other IPP projects, particularly in lower risk markets such as Egypt). In this context, the proposed increase in equity participation in new projects appears potentially counterproductive as it may further reduce investors return on equity.

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Table 4.3: IPP project debt¹

Amount (US\$ million)	Interest Rate	Tenure	Description
Sidi Krir D/E (33/67)			
Available: US\$342.5 Drawn down: US\$339.1 (278.6) ²	-	-	Debt structure set up in 5 tranches (B and C have amounts outstanding as of 2006). All tranches unsubordinated and rank pari passu with each other
US\$35	1.75% over LIBOR ³	Paid off shortly after COD	Tranche A: shareholder funding to fund ongoing costs during construction (considered part of equity in D/E ratio calculated by sponsors)
US\$164.3	1.75-2% over LIBOR (approx 7.5-8%)	12 years	Tranche B: US dollar facility provided by local Egyptian banks. Rate of 1.75% over LIBOR up to COD and 2% thereafter
US\$114.3	1.75-2% over LIBOR	9 years	Tranche C: US dollar facility provided by international lenders (but with some local Egyptian banks also included in final syndication)
US\$6	1.75% over LIBOR		Tranche D: US dollar working capital facility to cover costs in the event of delay of customer payments (not included in total debt costs)
US\$19.5 (presently revised to US\$5.2, equivalent to approximately 1 month capacity charge)			Tranche E: US dollar Letter of Credit or performance guarantee required by PPA under construction and reduced to US\$5.2 million thereafter (not included in total debt costs)
Port Said & Suez D/E (75/25)			
Available: US\$495 Drawn -down: US\$468	-	-	All loans unsubordinated and rank pari passu with each other, no corresponding allocation of funds as per Sidi Krir available at this time
US\$45 million per project Total of US\$90	Not Available (NA)	19 years	IFC A loan: IFC's own account
US\$152 million per project total of US\$305	NA	19-17 years	IFC B loan: IFC syndicated loans
US\$50 million per project total of US\$100	NA		IFC facilitated: Institutional Investor Debt (John Hancock)

Source: compiled by author, based on unpublished Sidi Krir and EDF data

Notes: ¹ Due to sensitivity of data, much of the information is not publicly available (NA); ² Total of 5 debt tranches for Sidi Krir described in table add up to US\$339.1 million not US\$278.6 million as Tranche A is treated as equity in Debt/Equity ratio and neither Tranche D nor E are counted as part of the direct project debt; ³ LIBOR: London Interbank Offered Rate.

For Port Said and Suez, however, the debt was sourced by the International Finance Corporation together with a syndicate of international banks and institutional investors, and the projects saw no local bank involvement.

The difference in debt financing between the EDF and InterGen/Globeleq plants is closely related to how the debt was denominated. Although sourced by local banks, the Sidi Krir local debt of US\$164 million was denominated in US dollars. Reasons given for the US dollar denominated debt are four-fold:

- the loans were available at comparable rates with other, international banks;
- the difference in the interest rates in both currencies was in favour of US dollars;
- IPP earnings were denominated in US dollars; and finally
- using dollars, rather than Egyptian pounds, helped eliminate all currency risk premiums from the bidders' quoted tariff prices thereby leading the government to secure the lowest possible bids, but also shifting the currency risk to the government.

While EDF was also eager to obtain local, Egyptian dollar denominated debt, the government did not make any such loans available (Egyptian-pound denominated debt was not acceptable to the firm for reasons related to currency risk). Allegedly dollars were still abundant in local Egyptian banks, but there was insufficient political will to mobilise these resources for power plant developments.¹⁸⁷ With European commercial banks reluctant to invest in what they deemed insufficiently environmental projects (i.e. plants were for gas-fired steam generators and not combined cycle), EDF turned to a multilateral, namely IFC to help secure additional debt.¹⁸⁸

IFC subsequently provided to EDF a US\$90 million loan with a maturity of 19 years and arranged, together with Societe Generale and Barclays, a multi-million dollar syndication, with maturities of 19 and 17 years. Among the largest single holders of debt in Port Said and Suez is the USA-based insurance firm John Hancock with US\$100 million lent.¹⁸⁹ In contrast, for the Sidi Krir project, there was no need to engage a development finance institution to secure funding. Although Sidi Krir was the first IPP in Egypt, the local, US dollar denominated debt component provided the assurance that international banks needed to participate (Thomason 2004).

In sum, Sidi Krir was able to access competitively priced dollar denominated financing from local banks. EDF was provided with no such financing option, and as a result, EDF had to

¹⁸⁷ One recent indication from local bankers is that Egypt's local capital markets/banks may be used for future investments planned for metro, roads and ports, but no plans are on the table to target these funds for the power sector, which is being financed largely by concessionary loans (personal correspondence March 2006).

¹⁸⁸ The same environmental issues were not, however, raised by European banks for the Sidi Krir project (selected correspondence with Globeleq, April 2005).

¹⁸⁹ The presence of an institutional investor in emerging market power projects is noteworthy. If replicated, such involvement could transform electricity developments given the size of institutional investors.

seek out a multilateral development institution (although it in turn did engage a significant institutional investor in the form of John Hancock). Following on EDF's experience, the next IPP framework clearly stipulates that all foreign currency must be sourced from abroad. This change in policy may imply a negative development outcome, which the Government of Egypt is now seeking to rectify.¹⁹⁰

4.6.3 Secure and adequate revenue streams and other risk management

Just as the government may be seeking to alter the structure of financing for future IPPs, steps have been taken to ensure that no more PPAs are signed with the same conditions as granted to the first three developers, as described in section 4.2.3, with the largest difference related to new IPPs being required to come up with their own off-takers to consume the power. The new IPP framework has not, however, had any impact on the existing PPAs—even despite the fact that capacity payments in Egyptian pound equivalency have doubled for the off-taker. The three PPAs signed by InterGen/Edison and EDF are similar in nature. The PPAs stipulate a BOOT project structure for all three IPPs. The rationale provided by EEHC for such a structure is that there was general public concern over ownership.¹⁹¹ The “T” or transfer component helped reduce political pressure, by assuring the public that after 20 years plants would be returned to the state. EEHC would then operate them for an additional 20 years (as plant life was estimated at 40 years). The Table immediately below presents the allocation of risks in the PPAs over the course of the development, construction and operation phases. The developers assume the majority of the risk during the first two stages, with the off-taker taking on the bulk of the risk in the operation stage.

¹⁹⁰ Project finance was arranged by Kuasa for both Port Said and Suez and would also be for Sidi Krir.

¹⁹¹ It should be noted that despite considerable equity changes, there has been no alteration to the project structure.

Table 4.4: Risk allocation in Egypt's IPPs

Phase	Risk	Risk component/description	Allocation
Development	Financing risk	Developer may not be able to obtain sufficient financing	Developer: EEHC entitled to performance guarantee of US\$20 million
	Permitting risk	Failure of developer to timely obtain permits	Developer: EEHC entitled to performance guarantee of US\$20 million (EEHC, however, assists and bears the risk provided gvt delays)
Construction	Increased construction cost	Cost overrun due to developers own cost	Developer
		Construction cost increase due to contractor	Developer
	Delay in project completion	Contractor default	Developer: PPA details daily damages to be paid by Developer
		Failure to complete transmission facilities	EEHC: PPA details daily damages to be paid by EEHC
		Force Majeure (FM) events	Developer AND EEHC (Developer excused and deadline adjusted)
	Legal risks	Change in law	EEHC: if changes cause increased costs, prices will be modified
Operating	Dispatchability	Based on assumption that plant is fully dispatchable by EEHC in accordance with economic loading	EEHC, i.e. take-or-pay contract
	Capacity and availability conditions	Sustain capacity: risk that plant output or availability degrades over time	Developer: capacity payment in accordance with tested net capacity
	Fuel charge	Risk fuel price changes	EEHC*
		Heat rate risk: risk that efficiency of plant degrades overtime	Developer
		Minimum take-or-pay under fuel agreement	EEHC
	Force Majeure risks (FM)	FM leading to interruption in operation	EEHC: will continue to pay capacity charge
		FM leading to additional cost	Developer AND EEHC
	Legal risks	Change in law	EEHC: if changes cause increased costs, prices will be modified
	Conditions of plant at time of transfer	If plant output or heat rate are lower than guaranteed values	Developer

Source: adapted by author from EEHC (Egyptian Electricity Authority 2000)

Note: *Fuel price is not, however, a direct pass-through.

Finally, an added assurance in the PPA is a provision for international arbitration. As a default, disagreements are to be settled at the Cairo Regional Centre for Commercial Arbitration, under Egyptian law, in English. Should either party request it, however, arbitration proceedings may be conducted in Paris or Geneva and settled in accordance with the rules of the International Chamber of Commerce (Egyptian Electricity Authority 2000). To date, no disputes have required arbitration.

The PPAs for Sidi Krir, Port Said and Suez were contingent on two additional agreements coming into effect, namely: the fuel supply agreements (discussed at length in section 3.2.4) and the Central Bank guarantees, which were signed directly between IPPs and Gasco and the Central Bank, respectively. With regards to the Central Bank guarantee, all financial obligations by the off-taker, namely EEHC, as specified in the PPA, are backed by a Central Bank guarantee. According to developers, these guarantees were a necessity given the immature IPP market in Egypt, as noted in the context of investor perception.

4.6.4 Positive technical performance and strategic management

The way in which different projects were managed did not appear to make a significant impact, although there are minor instances worth noting. Stakeholders at InterGen highlighted unforeseen circumstances related to investor risk assessment and project management, associated with a lower than expected return, i.e. 8-10 per cent rather than 15-18 per cent, initially expected. These circumstances comprise: unanticipated premium increases in the world insurance market; i.e. one year premiums for Sidi Krir were US\$5.2 million instead of US\$1.2 million as budgeted; unrealized estimated availability of higher calorie fuel, which did not materialize; and finally the firm was unable to take advantage of low interest rate environment (interest rates decreased after the signing of the PPA) due to the fact that 80 per cent of the debt was hedged.

For EDF, Port Said and Suez have been relative investment successes with the company reporting that it made “modest profits” and ultimately met its profit targets (with the sale of its plants in March 2006), achieved in part through management of technological risk.¹⁹²

4.7 Final outcomes and conclusions

The IPP experience in Egypt appears to be positive: private investments were made in three substantial gas-fired plants that continue to deliver reliable and affordable power. While original project sponsors have departed, new investors have been willing to take equity. And despite a massive currency devaluation, dollar denominated PPAs have held, which has obviously been good for investors; less so for the off-taker, although cheaply sourced local gas has meant that PPAs are still competitively priced by international standards. It may be concluded that development outcomes (reliable and competitively priced power) have been in broad balance with investment outcomes (chiefly, adequate returns).

The main elements contributing to success are multi-fold. Egypt (along with Morocco and Tunisia) is characterized in part by their relatively favourable investment climate, which has

¹⁹² Although EDF interviewees were not able to report the project’s target or actual ROE due to shareholder agreements, they did indicate that “[we] assume that [profit targets] match those of other IPP developers, but it is hard to say”. It remains unclear, however, whether EDF, a public utility, would indeed have the same profit targets as other private IPP developers.

gone a long way in attracting FDI into the electricity sector. Although not presently investment grade, Egypt is just one notch below (at BB+) (Chambers 2007). One stakeholder cited the following features that contributed to an attractive investment climate, dating back to the first IPP tenders:

...a proper business environment; political stability in the country and the region; the government's economic policy (monetary and fiscal policy); an active capital market; an efficient banking system; a stable inflation and exchange rate; the repatriation of profits; the degree of enforcement of contracts; the degree of corruption; the country's labour force and the availability of a well educated productive labour force at a reasonable cost; the expected demand for goods and services in the near future; the country's geographical location; the ability to export to other near by markets based on signed trade agreements with EU countries, Arab countries & African countries (Egypt exports excess electricity to Jordan); and finally the experience of other local and international investors.

Reinforcing a favourable investment climate was Egypt's first IPP policy framework and planning, which was also notable for its investor-friendly approach. Both of these elements have in turn been linked to a successful international competitive bid process as well as favourable equity partners and favourable debt arrangements. Abundant low cost fuel and secure fuel arrangements have also helped pave the road to success, as have positive technical performance. The 2002-3 currency devaluation, among the most significant stresses to the country's macroeconomic state since the inception of the IPPs, has caused a change in the power sector reform programme but not altered any of the existing IPP contracts. There has also been no evidence of the obsolescing bargain or creeping expropriation, which is generally attributable in the case of Egypt to: robust and equitable contracting arrangements as well as strong local management and relationships—although equity turnover has been substantial. Of little significance throughout has been the role of the regulator, established shortly after the PPAs for all three IPPs had been negotiated.

Yet a closer examination of the IPP experience reveals a slightly more nuanced picture, as neither the original project sponsors, nor the government, consider future IPP investments (along the same conditions) in Egypt likely. Thus, existing projects appear to be sustainable, but not the overall framework. What then does this say about power sector reform?

After its initial IPP experience, the Government of Egypt once again relies primarily on the national electricity utility (EEHC) to build new generation plants. This decision was influenced in part by the unhappy experience of being exposed to foreign denominated financing which doubled local PPA costs as the currency collapsed, and partly because of the renewed availability of concessionary finance from DFIs (albeit with conditions as seen in the

recent World Bank loan for the El Tebbin gas-fired plant to address issues related to the utility's financial performance and pricing structure). It appears that the original decision to open its market to IPPs was largely a result of advice from multi-lateral agencies, such as the World Bank, who were withdrawing from infrastructure finance in the 1990s, and was not home-grown. International consultants, schooled in their own countries power sector reform programmes, may have reinforced this decision as well. While there has been no serious attempt by Egypt to renegotiate these PPAs, or to expropriate IPP assets, the country has effectively shelved future IPP plans, following its first framework. The original plans to build 15 BOOT projects that were advertised with site, technology and schedule, and were among the most attractive elements of the IPP market for InterGen and EDF in the late 1990s, no longer exist. Instead, new IPPs now face rules that require partial local currency denominated PPAs that have to be concluded directly with large customers (thereby substantially increasing the commercial risks). EEHC is no longer interested in assuming such risks and instead, an attempt at a bilateral market and wholesale competition is in the making.

Tanjong, which may soon own all of the large-scale IPPs in Egypt, has indicated that it would potentially be interested in such new IPP investments, provided there is a sufficiently robust policy framework (including favourable resolution of the current natural gas debate), as well as creditworthy off-takers. This stands in direct contrast to Globelec and EDF, who, when asked whether they would entertain such investments, responded negatively. Thus a new equilibrium appears to be emerging with new market players.

Unresolved, however, is the natural gas debate. As Egypt develops its gas export market via both LNG and pipeline, will low gas prices be available to future IPPs? If not, how will the next series of IPPs, now responsible for bringing their own customers, foreign currency (from abroad) and substantial domestic financing, be in a position to outbid government and take home a profit? Are the cards stacked against future developers at least for the near-term?

Investors were originally willing to enter the Egyptian market because they perceived a favourable investment climate and a promising prospect of new IPP orders. They were also able to minimize risk through a Central Bank guarantee, a 20 year PPA with a single-buyer, EEHC, which also helped assuage any concerns that could have arisen with an immature regulatory environment. However, within a few years, the original project sponsors of Sidi Krir (InterGen and Edison) departed and the developer of Port Said and Port Suez (EDF) has sold its assets. Reasons for exiting probably relate more to their global retreat from emerging markets – although the above shift in policy by the Egyptian state has no doubt contributed to their decision.

Had local currency financing been acceptable to investors, the Egyptian story may have had a very different ending. The devaluation would not have led to a doubling of capacity payments (in Egyptian pounds) and plans for additional IPPs may have been pursued. At the

same time, the more organic push for wholesale competition may also have been stunted. What remains to be seen, is whether policy shifts will once again occur to facilitate private investment in the power sector in Egypt to respond to growing needs for new capacity.

Chapter 5

Kenyan IPPs

5.1 Introduction: the IPP challenge

In Kenya, as evidenced in Egypt, by the 1990s, the country had insufficient public funds to cover the costs of necessary power expansion. There are, however, important distinctions. First, a general aid embargo had been imposed on Kenya throughout the early and mid-1990s, for reasons linked to corruption and lack of advancement in the creation of a multi-party state, which affected all sectors, including power. Secondly, Kenya was already facing supply shortages. As a result, the conditions, one could argue, were considerably more extreme than those found in Egypt, and therefore consequently the impetus to move toward private participation, stronger. It was with this backdrop that Kenya procured its first two stop-gap IPPs with contracts of seven years.

Toward the end of the 1990s, the aid embargo was lifting. Still, the country found itself with limited funding options, and subsequently signed up for what has been previously defined (in Chapter two) as the standard model for power sector reform. In 1997, a US\$125 million loan package from the World Bank provided funds to add about 220 MW of geothermal and diesel capacity to the grid, but the loan was conditioned on: unbundling generation from transmission and distribution; the establishment of an independent regulator; tariff increases; and increased private participation in the sector, via IPPs.¹⁹³

This Chapter examines Kenya's experience with IPPs, which had a combined capacity of 190 MW or over 15 per cent of the total installed capacity in the country. The IPPs have generally contributed more than 15 per cent of total generation, particularly in drought years. All IPPs signed PPAs with the partially state-owned distribution and transmission firm Kenya Power and Lighting Company. Only three of the four IPPs are in operation as of 2006, as the second IPP, Westmont, did not negotiate another contract after its seven year PPA expired in 2004.

It should be noted at the outset, that although emergency power plants have played a significant role in Kenya's power supply in 2000/01 and then recently starting in 2006 again, these projects, which have short-term contracts (1 to 2 years) with the Ministry, are not considered traditional IPPs and therefore will not be analyzed in detail in the text.¹⁹⁴

¹⁹³ Total MW installed eventually came to 312 MW. Concessionary loans were also provided by EIB, Germany's Reconstruction Loan Corporation (KfW) and JBIC to undertake this programme of reform. The Government of Kenya contributed directly as well as through its state utilities. Actual disbursements did not, however, match initial commitments with the World Bank through an IDA credit providing the bulk of support of US\$108 million or 55 per cent of the total package (World Bank 2005c:14).

¹⁹⁴ Plants provided by Cummins, Deutz and Aggreko, totaling 105 MW, were rented for 1.5 years between 1999-2001 to plug the power shortage during the drought. Actual capacity installed was 99 MW

The first part of the Chapter provides a brief overview of the sector as it stands at present (mid-2007), and is followed by a discussion of the electricity sector reforms undertaken to date. Thereafter the discussion turns to a close look at the IPPs and the frameworks under which they were developed. Subsequently, a contrast of the performance among IPPs and state owned entities is provided. Finally, the Chapter seeks to shed light on how and why development and investment outcomes changed over time. What role for instance did the investment climate, the regulator, local partners, PPAs and security agreements play in this balancing act, as attempts were made to ward off, as clearly indicated by one project sponsor, the potential of the obsolescing bargain? While the power sector reform model provided the context for the IPPs and goes a long way in explaining what actually occurred in terms of the two different sets of plants, what were the other factors to shape outcomes, and what might be noted as contributing to success?

Over 30 interviews were conducted with more than 20 stakeholders in January, February, August, November and December 2005 in Nairobi, Washington D.C. and via teleconference in Israel. Interviews were followed by email correspondence and follow-up calls to clarify discussion points, with the last review conducted in May 2007. Stakeholder interviews included present and former directors and managers at the Electricity Regulatory Board, Iberafrica, Industrial Promotion Services, International Finance Corporation, Kenya Generating Company Limited, Kenya Power & Lighting Company Limited, Ministry of Energy (MoE), Ormat, and Tsavo Power Company, Wartsila, Westmont, and the World Bank. *Due to sensitivity of data, the names of stakeholders, who have been the primary source of data for this thesis, have largely been left out of the discussion; most stakeholders are only identified, if at all, by organizational affiliation in the text. As a result, much of the data, which forms the basis of this Chapter, is not cited. In certain instances, however, where stakeholders have indicated their willingness, citations do include names and the designation of "per com" for personal communication.*

5.2 Primary players in Kenya's ESI

Among the most notable aspects of Kenya's ESI, particularly in contrast to the Egyptian case examined in Chapter four is its low access rates. According to the Kamfor Study, the latest

as Deutz delivered 24 MW instead of the 30 MW contracted. A World Bank IDA credit of US\$72 million was made available to pay for these plants. Due to the fact that fuel was treated as a pass-through cost to consumers, however, end-users bore the bulk of the high operating costs, with government providing a subsidy only for the capacity charge. The overall high retail cost of the emergency power plants was a function of the fuel costs and the capacity charge: the fuel cost was high due to inland transportation costs and the capacity charge was high due to the short duration of contracts as well as the negative investor perception of Kenya's power sector (World Bank 2000). In April 2006, Aggreko returned to Kenya to provide 100 MW under a 12-month temporary power package (*Kenya: Aggreko seals 100MW supply deal with Nairobi* 2006:4).

assessment carried out by the Ministry of Energy in 2000, 15 per cent of the Kenyan population has access to electricity, with access in urban areas measuring 47 per cent and that in rural areas a mere 3.8 per cent.

As of 2007, the Kenyan ESI consists of five different generation companies, and one integrated transmission and distribution company—the latter also acting as the counterparty in power purchase arrangements with the generating companies. Despite reforms and the introduction of IPPs, generation remains dominated by the majority state-owned Kenya Generating Company Limited, which accounts for approximately 80 per cent of all installed electric power generation capacity in Kenya (Kenya Power & Lighting Co. Ltd 2006, p.68). The remaining four generation companies, which make up about 20 per cent of installed capacity, are the three independent power producers, with majority stakes owned respectively by Union Fenosa, Duke-IPS¹⁹⁵, and OrPower4, as well as one emergency power producer (EPP), owned and operated by Aggreko.¹⁹⁶ KPLC, the transmission and distribution company is owned 48 per cent by the state, with shares traded on the Nairobi Stock Exchange (NSE) since 1954 (SAD-ELEC 2004:17-18; Kenya Power & Lighting Co. Ltd 2006).

Previously, imports from the Uganda Electricity Transmission Company (UETCL) met just under about 4 per cent of Kenya's demand, however, with persistent supply shortages in Uganda, imports dropped considerably in 2005/6 to a quarter of a per cent (Kenya Power & Lighting Co. Ltd 2006, p.68).¹⁹⁷ ¹⁹⁸ Finally, although representing less than one per cent of total installed capacity, it should be noted that the Rural Electrification Programme (REP), administered by KPLC and initiated in 1973, provides the balance, mainly in remote, isolated grids.¹⁹⁹

¹⁹⁵ Cinergy-IPS, the majority shareholder in Tsavo was a joint venture between Cinergy Global Power Inc and Industrial Promotion Services (Kenya) Ltd. As of May 2005, Duke Energy has bought Cinergy's stake.

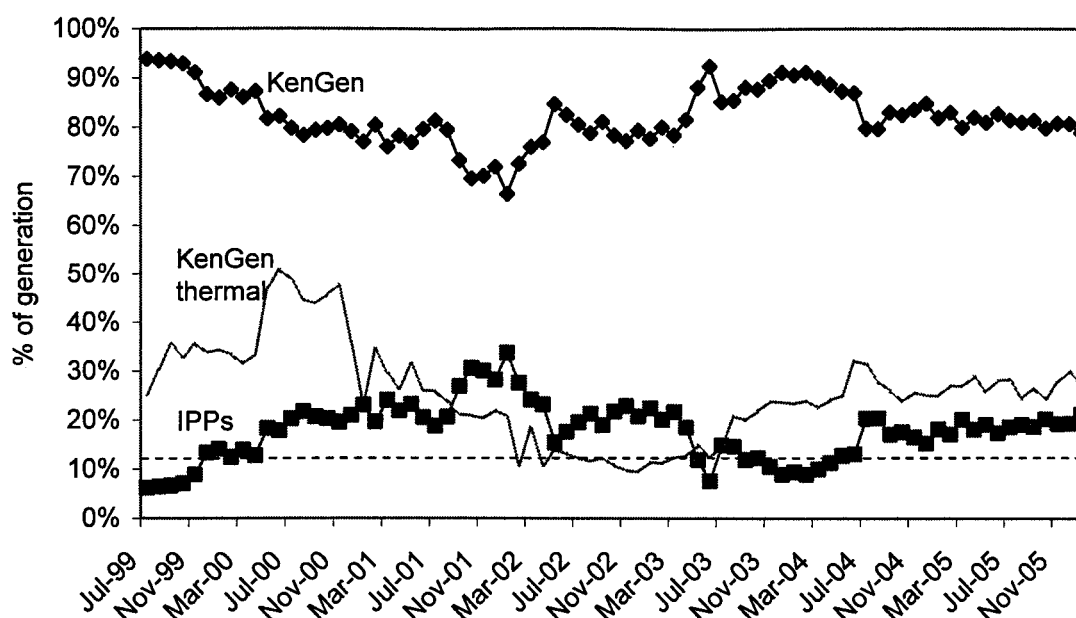
¹⁹⁶ Although often referred to as another IPP, including in KPLC's financial statements, Mumias, a cogeneration unit, which is part of a sugar factory, sold electricity to the grid in 2000/1, 2001/2, and in 2005/6, however, amounts are minimal with the installed capacity just 2MW and contribution to total production representing only 0.16 per cent of generation in 2005/6 (Kenya Power & Lighting Co. Ltd 2006, p.68). The factory is, however, presently considering increasing capacity to 35MW, which could potentially make it a more significant player in the ESI.

¹⁹⁷ Uganda historically supplied Kenya during low load periods, especially after midnight, as Uganda has no reservoir regulation. During peak hours, Kenya has in turn supplied Uganda with 10 MW (selected correspondence from Ministry of Energy, April 2005).

¹⁹⁸ Since 2004/5, KPLC has also imported nominal amounts from TANESCO—0.3 GWh in 2004/2005 and 0.4 GWh in 2005/2006 (Kenya Power & Lighting Co. Ltd 2006:68).

¹⁹⁹ REP was bolstered by the Electric Power Act 1997, which established the Rural Electrification Programme Fund (REF). REF is supported by a 5 per cent levy on all electricity consumed.

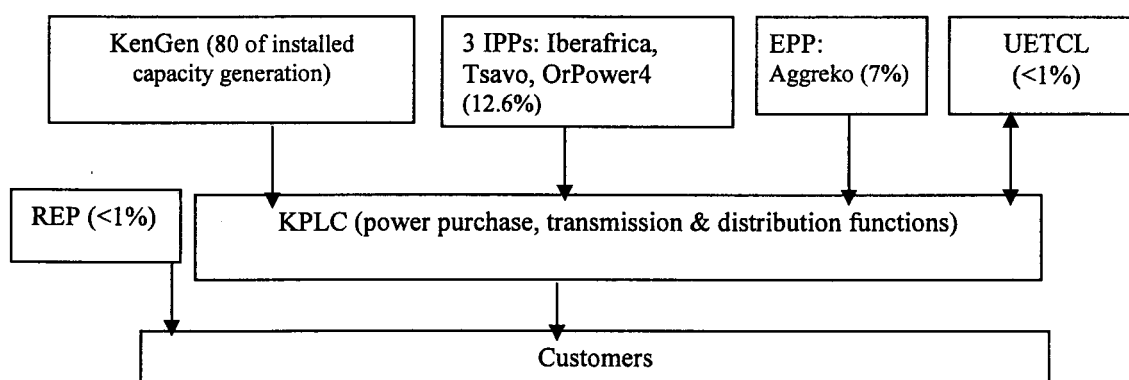
Figure 5.1 KenGen and IPP contribution to generation 1999-2006



Source: compiled by author based on unpublished KPLC data, 2006

Note: This Figure does not capture generation by EPPs

Figure 5.2: Kenya Electricity Supply Industry



The Ministry of Energy presently is responsible for formulating the sector policy to ensure efficient operation and growth, as well as preparing the least cost development plan, mobilizing investment funds and overseeing the rural electrification programme. The Electricity Regulatory Board, which is directed on policy measures by the Ministry of Energy, regulates the generation, transmission and distribution of electric power in Kenya. With the passage a new Energy Act in 2006, which is expected to come into force mid-2007, the ERB will be transformed into the Energy Regulatory Commission (ERC), which will regulate the entire energy sector (including petroleum). Other major changes include the licensing and appeals process, with the ERC to take over responsibility from the Ministry of Energy of issuing

licenses, and an energy tribunal to replace the current appeals process to the Minister. A final important change will be the creation of Rural Electrification Agency, which will also be part of the newly created ERC (Government of Kenya 2006:III:27(3),III:66-79,VI:107-109). Otherwise, ERC's duties with regard to regulation of the electricity sector will remain the same, as described below:

- Enforce environmental, health and safety regulations in the power sub-sector;
- Investigate complaints made by parties with grievances over any matter required to be regulated under the Electric Power Act;
- Ensure that there is genuine competition where this is expected;
- Approve electric power purchase contracts and transmission and distribution service contracts between and among electric power producers, public electricity suppliers and large retail customers. Approval of the PPA involves ensuring that tariffs are as low as reasonably possible, investor returns are reasonable, and safety is guaranteed for consumers
- Set, review and adjust tariffs for all persons who transmit or distribute electrical energy, based on a rate-of-return methodology with the majority of fuel costs and foreign exchange passed through to the consumer on a monthly basis, and
- Investigate tariff structure even when no specific application for a tariff adjustment has been made.

The last two tariff reviews occurred in August 1999 and May 2000²⁰⁰ during the power emergency caused by the drought situation. As specified in subsidiary legislation to the new Energy Act of 2006, tariffs are to be reviewed every three years. Adjustments for fuel and foreign exchange will, however, continue to be made on a monthly basis. It should be noted that by 1999 although average costs were increased from 30 per cent to about 100 per cent of long-run marginal cost, there is still significant cross subsidization. Household tariffs remain below the cost of service as a result of the general policy to promote affordability and offer a life-line rate (World Bank 2005c:29,38).²⁰¹

To date government has never overturned an ERB decision. While the Board maintains a significant degree of autonomy, in the first six years of its operation, it had five different chairmen (all appointed by the President), which it has been alleged may have undermined the institutional memory and capacity of the organization.

²⁰⁰ The 2000 change was simply a removal of off-peak tariffs due to the power rationing.

²⁰¹ Kenya's life-line tariff for the first 50 kWh of consumption applies to all domestic consumers. Efforts are currently underway by ERB to target this subsidy to the vulnerable members of society. Furthermore, Kenya maintains a uniform national tariff, i.e. no geographic differentiation, which avails a large subsidy to rural consumers. Efforts are underway to reduce cross-subsidies by industry.

5.3 The means and the ends: Power sector reforms and results

5.3.1 Power sector reform a la standard model, almost

Kenya's power sector reforms are inextricably linked to its relationship with multilateral and bilateral development institutions, most notably the World Bank, and a set of loan covenants. In this regard, there are sharp contrasts with the case of Egypt discussed previously, where, although such funding agencies played a role they were not, it could be argued, as influential.

As alluded to in the Introduction of this Chapter, in 1997, an agreement would be signed with the World Bank that made financing for new power (a 75 MW diesel and 64 MW geothermal plant) contingent on: the establishment of a legal and regulatory framework, including the passage of an energy law and establishment of a regulator; the reform of the organization, management and financial structure of the power sub-sector companies, the separation of generation from transmission and distribution functions; and the promotion of private sector participation in management of operations as well as via approximately 140 MW of new generation provided by IPPs (World Bank 2005c:2; Kenyan Electricity Regulatory Board per com 2007).²⁰²

Although discussions for this reform package commenced in 1988, activity related to the programme did not start until the mid-1990s, with financial closure for the loan finally reached in 1997. Delays are attributed to lack of agreement on the actual reform steps as well as a general aid embargo that would limit funding across all sectors throughout much of the early 1990s. It should be noted here, as first referenced in Chapter two in the case of Tanzania, international consultants, who were instrumental in power sector reforms undertaken particularly in the UK also played a key role in designing Kenya's reforms, with much of the work underwritten by World Bank funding (London Economics 1993; PB Power 2002; PB Power 2007; PB Power per com 2007; PricewaterhouseCoopers 2007; World Bank 2007h).²⁰³

Among the first steps taken in line with the power sector reform programme was the official liberalization of the electric generation sector in 1996. Although this step preceded financial closure of the World Bank deal, it was a necessary step to demonstrate the country's commitment to promote private sector participation and competition. From this time onward, it became government policy that all bids for generation facilities would be put out for competition, open to both public and private firms, i.e. the national generator would receive no preferential treatment.

²⁰² It should also be reiterated here (as noted in section 2.4.2) that although the World Bank did reduce its lending for power generation in the 1990s, the Bank did not withdraw from funding such investments entirely.

²⁰³ London Economics first authored a tariff study for KPLC in 1993. In 2002, PB Power completed an additional tariff study for KPLC and KenGen. PriceWaterhouseCoopers was the author of study on the organizational restructuring of KPLC, which was initiated in 2001.

While the power sector reform programme, discussed above, included plans for both privately and publicly funded new generation plants, by 1996 power supply shortages were severe, due primarily to the fact that the hydro-dominated system was being undermined by drought. With financial closure not yet reached for any of the new capacity, KPLC issued selective tenders for two stop-gap IPPs, with tenders awarded to Westmont and Iberafrica. Thus, it is important to note that although these two plants were funded by the private sector, they were not the privately financed plants foreseen in the loan documentation, as will be discussed in detail in subsequent sections, and a theme that will also be seen in the case of Tanzania.²⁰⁴

Reforms would continue with the passage of the Electric Power Act in 1997, which set in motion the unbundling of state utility in that same year. KenGen, which initially remained entirely in state hands, became responsible for all generation assets. KPLC assumed responsibility for all transmission and distribution assets and operations. It is also worth noting that KPLC was given the task to act as counterparty to PPA transactions with private power developers, despite the fact that KPLC's financial and technical operations were on the decline—with conditions further exacerbated from 1999-2001 drought, described below (World Bank 2005c:4,13,38).

Shortly thereafter, a regulator was established, also through the 1997 Electric Power Act. It took another year for the ERB to start operations, which meant that the regulator came into effect only after the PPAs with Westmont and Iberafrica had been negotiated.

At long last, in 1998, the IPPs, as specified in the World Bank loan documentation, began to emerge. In that year, the PPA with OrPower4 to develop between 28 and 100 MW of geothermal power, was finally signed—marking the third IPP (after Westmont and Iberafrica). Within two years, the PPA for the fourth IPP, also specified in the loan documentation, to be developed by the Tsavo Power Company, sponsored by Cinergy-IPS, Wartsila, the IFC and CDC, was signed. Although the World Bank IDA credit did not directly contribute finance to these two IPPs, funding was provided to two UK-based consultancies to assist KPLC during the procurement of plants (World Bank 2005c:3,5). Finally, at the very end of the decade, with conditions largely fulfilled, work would commence on the publicly led plants: Kipevu I, a 75MW diesel plant, an additional unit of 80 MW at the existing Gitaru hydro facility, and a 64MW geothermal plant, Olkaria II.

Just as the sector recovered from the impacts of the previous drought, in 1999 a second drought (which was characterized among the worst in five decades) threatened Kenya's supply. This in turn prompted the Ministry of Energy, with support from the World Bank via the Emergency Power Supply Project, to sign up three emergency diesel-fired power plants, which

²⁰⁴ The World Bank did, however, provide nominal support to the Government of Kenya to assist in negotiating these two stop-gap plants.

as mentioned in the introduction are not treated in-depth due to the short duration of contracts, negotiated with the government, not KPLC (World Bank 2000).²⁰⁵

Among the most significant impacts of the drought was that it required KPLC to seek out more costly thermal power options, which not only financially enfeebled the firm but also led to inflated prices for the consumer, as both foreign exchange and fuel costs were passed through in part. With IPPs associated with higher cost power, the drought led to a public outcry against private sector participation, which was seen to be taking advantage of a poor country in a dire situation.

Allegations of corruption in the power sector, together with a call to reduce tariffs, gained momentum. The new government, which came to power in December 2002, on the heels of the drought and a drought-induced recession, pledged specifically to address ESI reform and reduce tariffs. Among its first measures, the National Rainbow Coalition charged the Nyanja commission with investigating alleged corruption in the electricity and petroleum sectors. By December 2003, the Nyanja report was issued, indicting personnel in KPLC, Westmont and Iberafrica for corruption and flawed PPAs (*Kenya Risk: Infrastructure Risk* 2004). The Nyanja findings have not, however, led to significant changes in the sector, with the integrity of the commission itself being questioned along with the thoroughness of its investigation.²⁰⁶ While the Nyanja findings have been marginalized, ERB contends that its efforts to maintain tariffs “as low as reasonably possible” have been ongoing—before, during and after the commission’s investigation, as per the Board’s duties.

5.3.2 Recovery and the next set of reforms

Developments have continued to unfold, which are slowly changing the face of Kenya’s ESI, primarily by introducing more private participation and building existing capacity and institutions. While the World Bank and several other development agencies continue to play an active role in both shaping and funding sector policy, there has been considerably more ownership of the process and the outputs by the Government of Kenya, KPLC and KenGen.

In May 2006, KenGen together with the government led an initial private offering (IPO) for 30 per cent of KenGen’s share on the Nairobi Stock Exchange (NSE) in May 2006. The deal raised approximately US\$108 million for the state utility, with shares oversubscribed by four times what was offered (*Kenya: KenGen shares fly on Nairobi stock market debut* 2006).

²⁰⁵ It was estimated by the World Bank that without the emergency power facilities, losses to the economy would amount to US\$400 million or about 4 per cent of GDP over the period of a nine-month span, with costs for emergency power facilities estimated at US\$110 million (World Bank 2000:12).

²⁰⁶ Repeated attempts to obtain a copy of the Nyanja report were made through a range of stakeholders including at the MoE, ERB, KPLC, KenGen and each of the IPPs, but the report proved unavailable for public consumption.

A further of 19 per cent of KenGen is presently being considered for public sale.²⁰⁷ Unlike many of the previous reforms, this development neither was a condition of any lending agreement nor facilitated by concessionary loans.

Just two months later, in July 2006, KPLC commenced a two year management contract with Manitoba Hydro, which was intended to help the utility 'recover' from the aftermath of the drought and possibly prepare it for further privatization.²⁰⁸ In contrast to KenGen's IPO, concessionary loans have facilitated this activity, through the Energy Sector Recovery Project (ESRP), which is being led by the World Bank, however, with significant participation also on the part of the European Investment Bank, the Agence Francaise de Developpement (AFD) and the Nordic Development Fund.²⁰⁹ In addition, the ESRP is providing funding for the separation of transmission and distribution, and the establishment of a national transmission company. Although originally slated for end-2006, the establishment of such a transco will only be undertaken after a study is conducted—the consultants for which, as of June 2007, have yet to be hired (World Bank 2004c:3,38).²¹⁰

As for new generation capacity, apart from emergency power procured in 2006 under 12 month contracts as indicated earlier, and additional geothermal capacity to be provided by OrPower4, the primary developments are a 70 MW gas turbine, to be built by KenGen and an 80 MW diesel generator to be built by the private sector. Although the KenGen plant was expected online at the end of 2006 and the IPP by September 2007, both projects have been delayed.²¹¹ While delays have been encountered, it is not the result, this time, of failure to

²⁰⁷ Stakeholders in the government have indicated that it is too early (as of June 2007) to characterize the impact of the KenGen's sale on the electricity market, although proceeds from the sale have been used to help finance the emergency power procured by the government in 2006. It should also be noted that stakeholders in Kenya's existing IPPs have indicated that they have felt no impact from the sale, to date.

²⁰⁸ By 2003, in the aftermath of the drought, with KPLC's financial performance on the decline, the government intervened by reducing KenGen's bulk supply tariff as well as providing relief for interest on outstanding debt by converting considerable debt into equity. More specifically, KenGen has reduced its selling price by 25 per cent from Ksh 2.36 per unit (as set in August 1999) to Ksh 1.76 (as agreed in July 2003 with KPLC). KenGen also converted Ksh 12.3 billion in debt owed by KPLC into equity in September 2003.

²⁰⁹ It should, however, be noted that some stakeholders within the government question the need for such a management contract with KPLC previously under a performance contract and limited political interference since the inauguration of the government in 2002. On the other hand, several IPP developers indicated that there was a marked change in: the growth/ expansion of customer base, success of rural electrification programme, reduction of outages and reduction in T&D losses.

²¹⁰ The Energy Sector Recovery Project is an US\$80 million credit provided by the World Bank's IDA, with additional support from the EIB (US\$75 million), Agence Francaise de Developpement (US\$25 million) and the Nordic Development Fund (US\$12 million). In addition to helping to facilitate the management contract, the credit includes the following projects: institutional capacity building within both the Ministry of Energy and the regulator; several engineering studies related to the upgrading of plants as well as the establishment of a publicly-owned Geothermal Development Company; an extension for the Olkaria II plant, and a significant distribution upgrade, which comprises the bulk of the credit (World Bank 2004c:8-11).

²¹¹ An ICB was conducted for the 80 MW diesel generator (Rabai), and the bid was awarded to Burmeister & Wain Scandinavian Contractor, but was contested by Simba Energy (one of the bidders). The case was dismissed by the procurement board, but Simba has since taken its case to the High Court,

comply with reform conditions, as, like the IPO, none of these plants is tied to a larger reform package. Finally, the long awaited second phase of Sondu Miriu, a 60 MW publicly financed hydropower plant, primarily via concessionary funds from JBIC, is expected in November 2007. Initially Sondu was planned for the early 1990s but was abandoned during the aid embargo and amidst heightened environmental concerns.

Joint ventures with the state utility are under consideration as well. Furthermore, the governments of Kenya, Uganda and Tanzania have publicly committed to interconnection of the East-Africa region. An important element in this plan is the construction of a 220kV interconnector between Nairobi and Arusha in Tanzania, with support from the African Development Bank, among other funding agencies. While there is independent merit in an inter-connected East-African power system, significant gains can only be expected as soon as East-Africa is connected to the much larger Southern African Power Pool (SAPP) system, through the envisaged construction of an interconnector between Tanzania and Zambia. Realization of these interconnector projects could have major impacts on realization of potential future IPP projects in Kenya, as IPPs could potentially see more competition.

The Table immediately below highlights the myriad developments in the sector related to Kenya's power sector reform and IPP developments.

which in turn has meant that the project is at a standstill. In terms of KenGen's new 70 MW capacity, the plant has faced delays due to the fact that the Iranian-based contractor has not been able to import equipment from USA-based General Motors due to trade embargos.

Table 5.1: Kenya electricity sector developments

Date	Development
1922	East African Power and Lighting Company formed and held by private investors (present-day KPLC's predecessor)
1954	Kenya Power Company (KPC), established to transmit power from Uganda through the Tororo-Juja line (KenGen's predecessor); KPC managed by KPLC under management contract, i.e. establishing fully-integrated utility, with shares traded on NSE
1970	Government of Kenya obtained majority shareholding in KPLC
1991-1994	Aid embargo impacting all sectors
1995	Tenders for two IPPs initiated by MoE: one diesel (Tsavo), the second geothermal, (OrPower4)
1996	Government of Kenya decided to formally introduce competition into the generation sector
1996	Tenders for two additional "stop-gap" IPPs issued by KPLC, PPAs with Westmont and Iberafira signed; plants commissioned one year later
1997	ERB established under the 1997 Electric Power Act and subsequently ERB inaugurated in 1998
1997	KPLC and KPC unbundled and KPC subsequently named KenGen
1998	OrPower4 PPA signed for between 28 and 100 MW
1999, 2000	ERB sets new retail tariffs
1999-2000	KenGen resumed its expansion plans adding Kipevu I (Diesel) and Olkaria II as well as an expansion at Gitaru hydro, which had been planned in early 1990s
1999-2001	3 emergency IPPs introduced during drought (Aggreko, Cummins and Deutz)
2000	OrPower4 began to operate an early generation facility of 8 MW in June 2000 and added additional 4 MW for a total of 12 MW six months later; firm indicated that it could provide up to 48 MW following a resource assessment, assuming government guarantees provided
2000	Tsavo PPA (for 75 MW) finalized and plant commissioned in 2001
2003	KenGen reduced tariffs (as set in 1999) from Kenyan Shilling (Ksh) 2.36/unit to Ksh 1.76/unit
2003	Nyanja commission issued its report on the electricity and petroleum sectors, personnel from Westmont, Iberafira and KPLC indicted (among others) for flawed PPAs
2004	Iberafira signed 2 nd PPA for 15 years; Westmont stopped operating after the completion of its initial 7 year PPA
2004	New energy policy approved by Parliament and a new Energy bill, amending 1997 Energy Act submitted, which would introduce a number of changes, including increasing ERB's mandate
2005	National Social Security Fund (government entity) sells of 3% of its shares leaving 52% of KPLC in public hands
2006	Contract signed in April with Aggreko to supply 100 MW of temporary power for a minimum of 12 months
2006	KenGen sells 30% via an IPO
2006	New Energy Act is passed, expected to come into effect in mid-2007
2007	KenGen gas turbine and diesel IPP delayed
200?	East African interconnector

5.4 The IPP results

Kenya's four IPPs were developed in two distinct frameworks. Details of the plants and their corresponding frameworks are the subject of this and subsequent sections.

Table 5.2: Kenya's IPPs

Projects	Size (MW)	Investment Cost (US\$ million)	Fuel	Contract type	Contract Yrs	Project tender-Project operation
Iberafrica	56	65	Medium speed diesel, burns HFO	BOO	7, 15	1996-1997
Westmont	46	20	Gas turbine, burns kerosene/gas condensate (barge-mounted)	BOO	7	1996-1997
OrPower4 ²¹²	13	54	Geothermal	BOO	20	1996-2000
Tsavo ²¹³	75	85	Medium speed diesel, burns HFO	BOO	20	1995-2001
Total	190	224	-	-	-	-

As previously noted, the first IPP developments occurred on the heels of the 1996 policy reform and the emerging legislation (passed in 1997) opening up the generation sector to private investment. With power demand increasing, hydrological conditions weakening and insufficient public funds to build power plants, KPLC ordered two stop-gap IPPs in 1996. The PPAs stipulated seven year contracts for two plants: a 46 MW barge-mounted kerosene burning gas turbine plant and a 44 MW medium speed diesel generator plant, burning low sulphur fuel oil. Fifteen firms bid for these plants in what has been characterized as a selective international tender, i.e. with specific firms invited to bid. Of the 15 firms, Westmont, a Malaysian consortium, and Iberafrica, with majority shares owned by Spain's Union Fenosa, submitted the lowest bids and subsequently secured the contracts. Plants were commissioned less than a year later helping to plug the power shortage. It was here that the first IPP framework began and ended, as all subsequent plants would be developed under different conditions.

The second IPP framework, interlinked with the World Bank led Energy Sector Reform and Power Development Project, began to materialize in 1998 (although tenders for plants were considered as early as 1995). OrPower4, owned 100 per cent by Ormat, a USA-Israeli firm, signed a PPA (in 1998) to develop up to 100 MW of geothermal power. OrPower4, through its own resource assessments, subsequently determined that there were 58 MW of proven geothermal reserves, which could support a 48 MW plant. It was agreed by stakeholders that development would happen in two phases: first 8 MW would be brought online, based on existing wells, followed by 40 MW. The actual development, however, has diverged significantly. During the drought-induced power crisis, starting in 1999, KPLC requested that

²¹² The OrPower4 plant, which is owned and operated by Ormat, is also commonly referred to as Olkaria III. For the sake of clarity, the author uses 'OrPower4' throughout this Chapter and other Chapters.

²¹³ The Tsavo plant, which is owned and operated by Tsavo Power Company is also commonly referred to as Kipevu II. For the sake of clarity, the author uses 'Tsavo' throughout this Chapter and other Chapters.

OrPower4 bring an additional 4 MW online, which the firm did, upon the signing of a supplemental PPA. Thereafter no further development (of the outstanding 36 MW) occurred. It was only at the end of 2006, after several years of negotiations, as well as an investigation by MIGA, and a reduction in the tariff by OrPower4 for the second phase, that construction commenced.

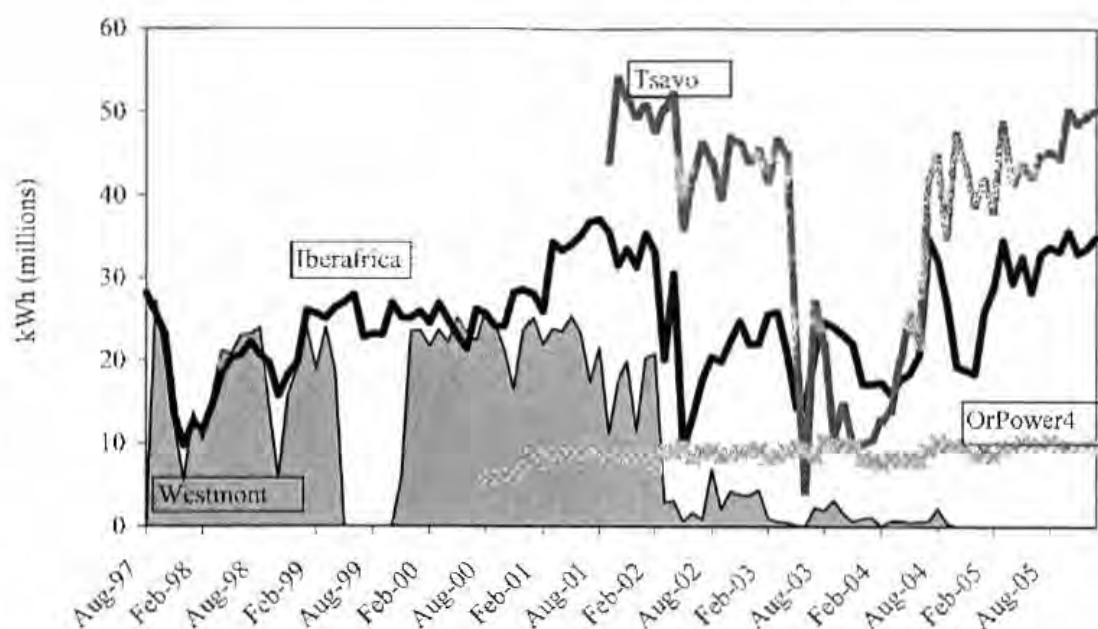
A further IPP was built during this second IPP framework: a 75 MW medium speed diesel generator, burning Low Residual Fuel Oil (LRFO). The PPA, awarded to the Tsavo Power Company, was finalized in 2000, and the plant came on stream one year later. Wartsila was the initial bidder, and subsequently brought on co-bidders, initially IPS, IFC, Cnergy and CDC (Globeleq). Delays in the Tsavo plant implementation have been attributed primarily to the financing. As Tsavo was the region's first project-financed power plant, there was little knowledge among stakeholders, and, the political risk prevalent at the time kept many potential funders at bay. In contrast to the first IPP framework, which was a selective international tender, both the OrPower4 and Tsavo plants followed international competitive bid guidelines. While this was considered a more transparent process, the competition was limited: only three firms bid for Tsavo and two (of which one was non-compliant) for the OrPower4 plant. The poor response from prospective bidders can be assumed to have been a result of general withdrawal of IPPs from developing country markets, investors' perceptions and assessment of specific Kenyan risks, and the lack of government guarantees being offered.

Kenya's next IPP, the 80 MW diesel generator in Rabai, Mombasa is being procured under largely the same conditions of the second framework. A Letter of Comfort is being offered by the Government of Kenya, but once again, government guarantees have not been extended (nor are they expected to be for future plants).

5.5 Operations and costs: the public vs. the private

It has already been seen that IPPs are contributing more than their share of generation (see Figure 5.1, which detailed generation mix and indicated on average that IPPs contributed well over 15 per cent, which represents their percentage of installed capacity). This section seeks to unpack each of the plants, starting with Figure 5.3 immediately below, which illustrates the contribution of each plant, to the country's generation mix.

Figure 5.3 Contribution of IPPs to generation mix



Source: compiled by author, based on unpublished KPLC data, 2006

Table 5.3 immediately below indicates average contribution to generation contrasted with the average installed capacity for each plant (for the period 1999-2006), with OrPower4 making the largest relative contribution based on its capacity, followed by Iberafrika, Tsavo and finally Westmont.

Table 5.3: IPP contribution to generation vs. installed capacity (1999-2006)

	% generation	% capacity
Westmont	3.27	3.67
Iberafrika	7.08	4.46
OrPower4	2.33	1.08
Tsavo	9.26	6.25

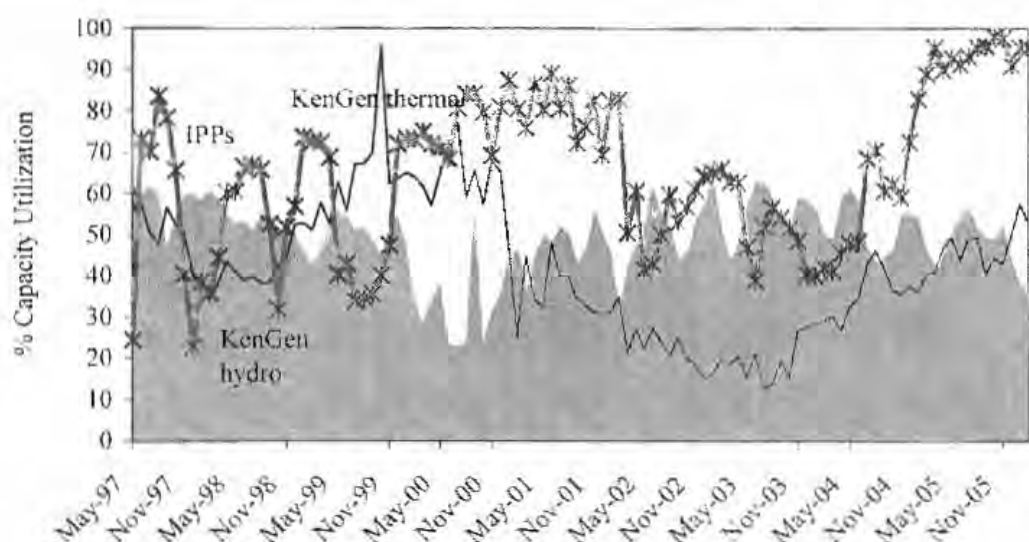
Source: compiled by author, based on unpublished KPLC data, 2006

This section seeks to unpack performance of both state-owned generators and IPPs and see who has supplied what, when, and at what cost.

In terms of availability, between 2004 and 2006, IPPs appear to have an average availability of approximately 95 per cent versus KenGen's thermal plants, which averaged 60 per cent. Prior to this period, availability of IPPs was slightly lower at approximately 90 per cent, due primarily to major outages by Westmont. Comparing availability among IPPs over the duration of their history, OrPower4 has an average availability of 98 per cent, followed by Tsavo at 92 per cent, Iberafrika at 89 per cent and Westmont at 77 per cent.

Given that IPPs have been more available, it is not surprising that their capacity utilization is higher, as indicated below.

Figure 5.4: Capacity utilization of IPPs vs. KenGen



Source: compiled by author, based on unpublished KPLC data, 2006

Wide discrepancies in utilization are seen among different plants, as would be suspected, with OrPower4, the geothermal plant registering a capacity utilization of often over 100 per cent.²¹⁴ Utilization for IPPs over the history of their operation is as follows: 103 per cent OrPower4, 66 per cent Iberafrika, 65 per cent Tsavo, and 35 per cent Westmont.

Finally, a price comparison reveals that IPPs are generally competitive with KenGen's thermal, as seen immediately below. Although it should be noted that, as with many state-owned firms, KenGen's costs might not be fully cost-reflective and not necessarily prepared in a manner that makes them directly comparable to the IPP cost of supply.

²¹⁴ In terms of OrPower4, the plant utilization is based on the contracted capacity (13.6MW) and the dispatch during the month; the plant may, however, do marginally higher than this declared figure. OrPower4 declared an output of 13.6MW to allow room for fluctuation when the geothermal production wells or ambient conditions may vary. During some months the plant performance is sustained at the higher output hence KPLC's calculation shows above 100 per cent utilization.

Table 5.4: Comparison of all plants (total generation nominal cost per unit Ksh/kWh)

Supplier	1999/2000	2000/01	2000/02	2002/03	2003/04	July-Dec 2004/
Iberafrika	8.7	10.2	10.2	10.9	10.4	6.4
Westmont	10.4	11.1	13.5	33.8*	59.7*	54.8*
OrPower4	-	6.1	6.6	6.4	7.1	6.1
Tsavo	-	4.2	5.6	6.8	11.1*	7.5
UETCL (imports)	5.3	5.5	4.8	4.4	4.4	4.4
KenGen Thermal	8.3	9.4	7.0	7.3	5.2	7.1
KenGen Non-Thermal	2.4	2.5	2.5	2.4	2.2	1.8
KenGen Overall	4.0	4.9	3.1	2.8	2.2	2.4
Mumias (bagasse)	-	6.6	6.7	-	-	-
EPPS (leased plant)	-	7.2	-	-	-	-
Annual weighted average cost per unit from all sources	4.6	6.1	4.4	4.0	3.3	3.6

Notes: IPP tariffs are a function of the capacity charge as well as volume of energy generated and the prevailing fuel prices. *These particularly steep costs reflect the following situation: in 2002-2004, there were more favourable hydrological conditions in Kenya hence the unit cost from thermal plants was high since the capacity charges are paid regardless of the amount of generation.

Source: compiled by author, based on unpublished KPLC data, 2006

In sum, it has been shown that IPPs are contributing more than 15 per cent (representing installed capacity) to the generation mix with Tsavo contributing the most in absolute generation (Figure 5.3) and OrPower4 contributing most in terms of relative generation (Table 5.3). Average availability of IPPs also seems to be greater than KenGen's thermal as is capacity utilization, with OrPower4 again ranking first in both categories followed by Tsavo for availability and Iberafrika for utilization. Tariff-wise there is considerable discrepancy among IPPs depending on the period; if one excludes Westmont and focuses on the renegotiated Iberafrika rate, however, prices appear to be comparable, with competitive rates seen especially for Tsavo in 2000-2002.

5.6. Balancing act?

Is there truth in the allegation (that predominated during the 1999-2001 drought) that investors have been taking advantage of a poor country in a dire situation? Or, have investors seen potential profits diminish with the onset of the obsolescing bargain? Which way are the scales tilted if at all and what does this say about the sustainability of the projects?

Initial stop-gap IPPs were expensive, with wholesale tariffs more than three times KenGen's. In the second wave of IPPs, the result was significantly cheaper power than the first

wave, with wholesale tariffs appearing to be competitive with KenGen's. During this second wave, Iberafrica (one of the initial stop-gap IPPs) also halved its capacity charge in its negotiations for a second PPA. OrPower4 also agreed to a lower return for the second phase of its project. In the end, Kenya experienced a fairly positive development outcome. The requisite power was supplied, albeit initially at a high rate to the country and consumer. Later, prices became more competitive. As for investment outcomes, in the first wave, it is believed that investors fared well given the high tariffs charged. In the second wave, outcomes appear to have been positive, but more modest.

Thus, outcomes appear to have been out of balance initially, with the scale tipped in favour of investment outcomes at the expense of development outcomes, with greater balance achieved over time. The Westmont contract, which was notable for its exceptionally positive investment outcomes, was not renewed, which would seem to confirm the hypothesis of this thesis that when outcomes are out of balance, the long-term sustainability of projects is ultimately at risk. An important point, also central to the main arguments of this thesis, should be made here, though. While Westmont's contract was not renewed, there was no evidence of the obsolescing bargain. All contract terms including those most onerous to KPLC were respected, until such time that the contract was over. A parallel may be seen here with Egypt. Post-devaluation, the state cancelled plans to build more IPPs; it did not, however, force the renegotiation of any existing contracts.

What led to the diverse outcomes? In particular, what contributed to the success of projects, particularly given the many exogenous stresses on projects?

5.7 Drought and other exogenous stresses

A one time exogenous shock as seen in Egypt is not in evidence in Kenya, but the country has experienced a gradual and significant devaluation of its currency, which has inevitably affected outcomes. Between 1980 and 1990, Kenya saw its currency depreciate by approximately 210 per cent, and then between 1990 and 2000, depreciation was approximately 230 per cent. Insofar as all PPAs are denominated in US dollars, this creeping devaluation impacts on IPP outcomes. Investments are growing more costly as is fuel, which is imported in the case of Westmont (only up until PPA expiry in 2004), Iberafrica and Tsavo.

A second exogenous factor to be noted is drought. The first two IPPs, both diesel-fired, were rushed through to help plug the power shortage created by drought conditions of 1996-7. The third IPP (OrPower4) was requested to increase its capacity during another drought in 1999. In each of these instances, power was ultimately more expensive due to the emergency nature of the situation. Furthermore, after hydrological conditions returned to normal, the country was still locked into contracts with take or pay requirements.

5.8 Factors impacting on outcomes: the country level

Although already discussed in detail, it is important to reiterate the significance of the power sector reform plan, championed by the World Bank and made a condition for public financing for the ESI, as spelled out in the Energy Sector Reform and Power Development Project. It was this plan that initially advanced IPPs in Kenya and yet at the same time, due to the state's failure to comply with certain conditions, temporarily held back funding, which in turn led to the stop-gap IPPs of Westmont and Iberafrica.

The reform plan, once adopted, set in motion a series of reforms, including the establishment of an independent regulator in 1998. Thus, the stop-gap IPPs lacked the oversight of an independent third party, which may have scrutinized tariffs, and other terms of the contracts (especially contract duration) to a greater degree. Although Kenya's options were limited, given the donor embargo and investor wariness, an independent regulator would undoubtedly have helped in the negotiating process, which largely resulted in an outcome that favoured investors at the expense of development outcomes. In the next set of IPPs with Tsavo and OrPower4, the Electricity Regulatory Board played a critical role, insisting on lower tariffs. ERB also influenced the renegotiation with Iberafrica for a second PPA with KPLC, which ultimately culminated in a capacity charge equal to 50 per cent the original. The scrutiny of the regulator, however, came at a certain cost as negotiating time (highlighted below in the context of the Iberafrica negotiation) lengthened. Although the power sector reform plan and associated developments, including the regulator, go a long way in framing the context, this thesis maintains that there is more to the story than this one narrative; furthermore, it would be inaccurate to assign either full credit or blame to the World Bank or the standard prescription for shaping outcomes.

As regards Kenya's investment climate, it was lacklustre throughout the 1990s with a GDP compounded annual growth rate of 1.73 per cent from 1990 to 2000 and just 1.37 per cent between 1997 and 2000. Foreign direct investment fell by 3.40 per cent a year over the decade. Kenya faced a donor embargo throughout much of the 1990s, which also affected investments in the electricity sector. Although organized as international competitive tenders, the tenders ultimately awarded to Tsavo and OrPower4 only attracted three and two bids, respectively, as mentioned earlier. Therefore, those investors who did approach Kenya were few and far between and ultimately charged higher risk premium to offset the perceived high risks, which were exacerbated by the absence of sovereign guarantees.

As with the investment climate, Kenya's electricity market had a significant impact on outcomes. Firstly, although common among African countries, Kenya's power demand is miniscule (with just 1,200 MW installed capacity) compared to other developing countries in Latin America, East and South Asia, and Central Europe, which saw significant IPP

investment. Limited demand potential therefore inhibited investment. Another factor is that IPPs were perceived to be competing against 'cheap hydro', the incumbent fuel in Kenya (even though the most economically viable hydro sites had been exploited and the country faced drought conditions for much of the 1990s). This (mis)perception ultimately weighed against investors. KPLC, the off-taker, was characterized by poor financial performance.

Many of these themes, which were widely cited by stakeholders, are reiterated in the World Bank's Implementation Completion Report for the Energy Sector Reform and Power Development Project, which is also reported in the documentation for the Energy Sector Recovery Project.

A lesson learned from this experience is that while the private sector may be desirable to help a country large investment capital for infrastructure, it is necessary to ensure the overall political, macro, fiscal and regulatory environment are not perceived by the private sector as unduly high risk. A gradual reform approach, based on a comprehensive sector policy may have higher payoffs in the long-term (World Bank 2004d:6; World Bank 2005c:19).

It is, however, interesting to note that absent from the paragraph above is any reflection on the applicability of the reform prescription.

5.9 A host of project level factors impacting IPP development

While the country level factors, including the power sector reform plan advanced primarily by the World Bank and associated consultants, go a long way in describing outcomes, a number of project level factors also hold significant explanatory power. An examination of these factors also takes this thesis back to the question of whether Raymond Vernon's thesis of the obsolescing bargain, discussed in Chapter two and re-examined briefly in the case of Egypt, is relevant. Do deals negotiated with developing countries, which may at the time have less bargaining power, later come unstuck once the concrete is poured? If so, what are the (successful) ways that project sponsors have reduced or eliminated the effect of the obsolescing bargain? It should be noted at the outset of this analysis that in the case of both Tsavo and OrPower4, stakeholders indicated that there was evidence for the obsolescing bargain. Westmont and Iberafrica may have felt pressured by government as well, however, they did not articulate it as such; nonetheless the behaviours adopted by all stakeholders below indicate that they were trying to ensure their bargains remained intact.

5.91 Analysis of project partners

There was some variety in the project partnering across the four IPPs. Only one of the four IPPs, Iberafrica, had a local partner.²¹⁵ Two projects, Tsavo and OrPower4, saw the involvement of a multilateral development institution. Both Tsavo (through equity partner IPS) and Iberafrica had previous experience in Kenya, with IPS also identified as a more development-minded firm. Finally, Tsavo was the only project-financed deal, with the other three relying on the balance sheets of their sponsors.

In the case of Iberafrica, the local partner consisted of the KPLC Pension Fund (who owns 20 per cent of the project). According to personnel at Iberafrica, a local partner was considered a requirement for Union Fenosa given Kenya's country risk at the time of investment. While the alliance between Iberafrica and the KPLC Pension Fund may have helped assuage Union Fenosa, it has been subject to some criticism and controversy, namely that with involvement with KPLC, the off-taker, there could not be a fair and transparent evaluation of competing bids. These allegations have been denied by both Iberafrica and KPLC who argue that Pension Fund came in after the award of the project and hence there was no possibility for such influence; furthermore, the Pension Fund is governed independently from KPLC with a separate board of trustees.

On the one hand, the local partner assisted in providing security to the multinational firm; on the other hand, the choice of local partner ultimately raised doubts about the project sponsor's integrity, however, unfounded. Suffice it to say, actions speak louder than words and Iberafrica (with the partnership remaining intact between Union Fenosa and the KPLC Pension Fund) has managed to negotiate a second PPA, under the supervision of ERB, for a duration of 15 years, which would indicate that the arrangement is both sustainable and favourable.

While DFIs were largely absent in the first round of IPPs (with the exception of limited technical assistance), the IFC took both an equity stake in and played an important role in providing and arranging debt for Tsavo, a project that was specified by name and size in the World Bank funded Energy Sector Reform and Power Development Project (World Bank 2005c:3). As the private sector arm of the World Bank, IFC saw the Tsavo investment as a critical development to help meet rising power shortages in Kenya, which were adversely affecting the economy. Funds were not forthcoming from other international donors or the private sector as the former was still maintaining an aid embargo and the latter was hindered by the myriad of risks, heightened by the political instability, of any such investments. IFC thus saw its role as key in assuring private sector participants of project integrity and stability. IFC also recognized the potential "demonstration effect" of the project as it aimed to be the first project-financed deal in the region. Both the investors and host country alike have benefited

²¹⁵ The reason provided by OrPower4 for not engaging a local partner was because the project was too small.

from IFC's decision to participate in Tsavo, including, as cited by project sponsors, when there were signs of obsolescing bargain at the end of the 1999-2001 drought. It was at this time that IFC helped the project company resist pressure from the government to reduce its tariff.

As regards firms' commitment to the country, the difference in the commitment among project developers is stark. The Malaysian based firm Westmont had only one African project. The firm entered the market with the signing of its PPA in 1996-7 and left promptly in 2004 after failing to agree on a tariff with KPLC for a second PPA. It is suspected that this abrupt departure was in part a function of the financial condition of Westmont's parent company in Malaysia as well. That said, there was little staying power and ultimately little long-term success. Iberafrica stands in contrast. Union Fenosa, the majority stakeholder in the project, entered Kenya in 1994-5, two years prior to the electricity offer, when its information technology (IT) arm won a contract to provide services to the government. Thereafter, the company established itself in the country, creating favourable ties and a solid name for itself. Tsavo's commitment is observed through its equity holder, IPS, which has been active in Kenya since the 1963. Finally, Ormat's commitment spans only the time of its contract. The firm entered both the country and the continent for the first time when it signed its PPA with KPLC.

One additional point should be made here about the nature of the firms. While Tsavo Power Company had no local partner per se, it did benefit from the involvement of the Industrial Promotion Services Kenya Limited, which as previously noted is a subsidiary of Aga Khan's Fund for Economic Development, which operates through its subsidiaries in the industrial sector throughout Asia and Africa. While IPS projects must make commercial sense, they must also serve a clear developmental function for the country/community. The Tsavo plant met both criteria for IPS. The developmental function was met by the fact that the 75 MW would help Kenya plug a severe power shortage, i.e. the plant amounted to 28 per cent and 34 per cent of the country's total thermal/geothermal generation in 2001-2002 and 2002-2003 respectively, and up to 10 per cent of the total gross annual energy requirement in 2002-2003. In addition the plant was expected to contribute to a reduction in tariffs, as it was significantly less expensive than emergency power generation procured at 0.30-0.40 US\$/kWh. According to stakeholders at IPS, the commercial aspect was met by the fact that: a reasonable return on investment was expected (i.e. mid-teens); a series of first rate investors were involved; and the security package, together with the 20 year PPA, promised a sound and secure arrangement with the national utility. Ultimately, IPS played a substantial role as it formed the backbone of the strategic partnership with Cinergy (later Duke); together these two firms represent 49.9 per cent of the equity in Tsavo. Hence, it may be concluded that this development-minded firm had a positive impact on both the development and investment outcomes.

Although as indicated in section 5.5, OrPower4 receives the highest marks for actual performance, it is Tsavo that has been characterized as the most successful from both a development and an investment perspective by a range of stakeholders for its absolute contribution to generation, lower tariffs (than emergency power and most IPPs) and unprecedented financing structure, as discussed in greater detail in section 5.9.2.²¹⁶ It is also the firm with the longest commitment to Kenya, and with a clear development mandate.

5.9.2 Funding arrangements that made the IPPs

The financing arrangements for each of the IPPs are quite distinct. In the case of the stop-gap IPPs, firms were given 11 months to bring plants on line from the signing of the PPAs, which meant that firms had to rely primarily on their own balance sheets rather than setting up elaborate project finance arrangements. Project costs for Westmont, the first stop-gap IPP, amounted to US\$20 million. Little is known about how exactly the Malaysian consortium funded this plant, but it is believed that it relied mostly on company funds. In contrast, the cost of Ibrafrica, the second stop-gap IPP, totaled US\$65.1 million and the firm shared costs with a local partner and through local and foreign commercial banks. The discrepancy in project costs, between the similar sized Westmont and Ibrafrica plants, may be attributed to three primary factors: namely, condition, technology and location. Westmont was a second-hand plant. Furthermore, it is a barge-mounted open cycle gas turbine (using kerosene), located off Mombasa while Ibrafrica is a new, diesel generator plant, located near Nairobi.

In contrast to Westmont, Ibrafrica's financing structure is more widely known. The project, which was carried out in two phases with the first phase of 44 MW priced at US\$54.5 million and the second phase of 12 MW costing US\$10.5 million. Project equity amounts to US\$ 18 million. Ownership is shared, with 80 per cent held by First Independent Power East Africa Limited—an entity owned by two Spanish firms, Union Fenosa (90 per cent) and JHR Consultants (10 per cent) --and 20 per cent held by the KPLC Staff Pension Fund. Project debt, amounting to US\$47.1 million, was provided directly and indirectly by Union Fenosa and the Staff Pension Fund as detailed below:

- Union Fenosa provided direct loans of US\$12.7 million;
- Union Fenosa also guaranteed a further US\$20 million;
- KPLC Staff Pension Fund provided direct loans of US\$9.4 (US\$5 million of which it borrowed itself); and
- KPLC Staff Pension Fund also guaranteed an additional US\$5 million through a local Kenyan bank.

²¹⁶ From an operational perspective, OrPower4 has met with the highest success (as per the availability, utilization and relative generation contribution) followed by Tsavo and Ibrafrica.

Tsavo followed a different route than its predecessors, Westmont and Iberafrica, with regard to financing. Unlike with the first two plants, Tsavo was not required to commission its plant within an 11-month timeframe, which allowed the company to seek out more creative financing schemes. Tsavo became the first project in East Africa to be financed on a project finance basis without government guarantees. Project equity, amounting to US\$18.93 million or 22 per cent of total project costs, was split among IPS-Cinergy (49.9 per cent), which comprises an AKFED subsidiary and an American-based power company. CDC, the private development arm of DFID, which has since been replaced by Globeleq (30 per cent), Wartsila, a designer and operator of power plants (15 per cent), and IFC (5 per cent).²¹⁷

Project debt for Tsavo, amounting to US\$ 66.06 million, came in the following form:

Table 5.5: Tsavo's debt

Type of Loan	Definition	Amount
Senior Loans:		
IFC A loan	IFC's own account	US\$15,100,000
IFC B loan	IFC syndicated loans	US\$22,100,000
CDC loan	CDC's own account	US\$13,000,000
DEG loan	DEG's own account	EUR 11,000,000
Subordinated loans		
IFC C1 loan	IFC's own account	US\$1,433,333
IFC C2 loan	IFC syndicated loans	US\$1,433,333
DEG sub-loan	DEG syndicated loans	EUR 2,000,000

Note: DEG: German Investment & Development Corporation

Given the absence of sovereign guarantees, which are generally a pre-requisite for a project-financed investment in a developing country, a series of alternate arrangements were made. Key documents for project completion were the Letter of Comfort provided by the government and the security package provided by KPLC. The Letter of Comfort addresses *force majeure* and political issues, but does not qualify as a sovereign guarantee due to its limited application and coverage. The security package involves: an escrow account to which KPLC must provide one months payment of approximately US\$4 million for the duration of 12 years, i.e. the period of primary debt repayment; and a stand-by Letter of Credit, which covers

²¹⁷ Interviews with stakeholders revealed that Cinergy has been increasingly less involved in operations of Tsavo. This should be seen as a result of Cinergy's decision around 2003 to pull out of all investments in developing countries, focusing on investments in the USA and Europe only. However, with Duke Energy buying Cinergy in May 2005, it remains to be seen what will be the future of this equity partnership.

three months billing of approximately US\$12 million. Initially 100 per cent cash cover was required for the Letter of Credit; however, this has since been eased to 20 per cent.²¹⁸

It should be reiterated here that no plants received government guarantees—although the costs of the emergency power plants were supported in part by government. Kenya has maintained a policy of not extending government guarantees to private sector projects, unless there is an overriding public interest.

In the case of OrPower4, financial closure has not yet been reached. The parent company, Ormat, has invested more than US\$54 million of its own funds—for both appraisal and drilling of the geothermal wells for its first 12 MW of power. Contrary to its initial expectation, Ormat has been unable to enlist either development financing institutions or any other international energy companies (although the firm did obtain a MIGA guarantee, discussed below). As with Tsavo, the provision of an escrow account, to which KPLC was to provide one months payment, and a stand-by Letter of Credit, covering three months billing, was included in the PPA signed in 1998, with the expectation that this security package would come into force upon the commencement of the second phase of the plant. This did, not, however, happen. Instead, with KPLC's financial situation deteriorating during and after the drought, the utility sought to reduce the tariff for the second phase. All associated security measures were left to wait.

With pressure from both government and KPLC intensifying in 2004, OrPower4 notified MIGA. Although the guarantee, mentioned previously, was never officially invoked, MIGA did send a delegation to investigate the deteriorating relationship, which ultimately resulted in eliminating the pressure from government, but not KPLC, to reduce the tariff. At the end of 2006, agreement was finally reached among stakeholders, which involved a reduction in the OrPower4 tariff for the second phase (constituting an amendment to the 1998 PPA), and the provision of the financial securities by KPLC. Orpower4 has since revived the process for arranging project financing from international lenders, and commenced construction of the second phase, expected online in the fourth quarter of 2008.

²¹⁸ The security of having a DFI involved should also not be underestimated as it may have gone a long way in assuaging investor concerns.

Table 5.6: IPP project financing

Project (US\$ million)	Westmont	Iberafrica	Tsavo	OrPower 4
Total project costs	20	65.1 ¹	85	54 ²
Total equity and %	NA	18 (27.6%)	18.97 (22.4%)	NA
Total debt	NA	47.1 (72.4%)	66.03 (77.6%)	NA
Local equity	0	3.6	0	0
Local debt	0	14.4	0	0
International (private) debt	NA	32.7	>26 ³	NA
DFIs	0	0	40	0 ⁴

Notes: ¹Iberafrica, total project costs US\$65 million, with first phase (44 MW) priced at US\$51.5 million and second phase (12 MW) at US\$13.5. ²US\$54 million includes the amount invested in a 12 MW power plant and completed geothermal wells for 58 MW including 20 per cent reserve to support a 48 MW power plant. ³Syndicated loans may be considered from a DFI from a risk perspective. ⁴MIGA guarantee provided.

In conclusion, it is noteworthy that Tsavo, which has been considered the most successful of the four IPPs by a range of stakeholders, had the most diverse project financing, although it was largely contributed or facilitated by multilateral development institutions, and the deal also took the longest to close. Success does not come cheap, at least not in terms of time.

5.9.3 From 7 years to 20: evolution of contractual terms

Among the most apparent differences in the two IPP frameworks is the duration of the PPAs—with the first stop-gap framework stipulating seven years, the second, specifying 20 years. In the first period, the Iberafrica and Westmont plants, providing about 100 MW of power, were seen as a “stop-gap” measure to quickly meet capacity shortages. Publicly financed plants, which were considered less costly, were in the pipeline, but funding was not forthcoming. Government opted for a short-term solution with the expectation that by 2004, if not before, when the PPAs were slated to end, the situation would be altered, i.e. potentially more favourably for the government/country. Furthermore, given the political risk at the time of stop-gap IPPs, investors were wary of committing to longer terms.

There is also a marked difference in the generating costs of the IPPs with the first wave (Westmont and Iberafrica) amounting to approximately double the cost of the second wave, (Tsavo and OrPower4) as depicted in Table 5.4. The higher cost of the first wave has been accredited to the short timeline allotted and severe drought condition. It is noteworthy that the second wave was not only cheaper than the first, but it also appears to be competitive with KenGen’s plants.

The major commonality among the PPAs of all Kenyan IPPs was the Build Own Operate structure. Reasons provided for why Kenya adopted the BOO structure are varied: it was a

simpler arrangement than BOOT; it was a World Bank recommendation; BOO mitigated project risk, by ensuring that developers would properly maintain their plants. The vast majority of stakeholders, however, appear to be uncertain about why such a structure was adopted. Also, it is worth reiterating in this context that going forward, government stakeholders are keen to explore the BOOT structure.

In addition to being BOOs, the PPAs signed between KPLC and project developers specified take-if-tendered conditions, i.e. the purchasing utility pays for an agreed amount of power produced whether it takes it or not, with the following availability levels stipulated: Westmont, Iberafrica and Tsavo at 85 per cent and OrPower4 at 92 per cent.

Of the four PPAs negotiated with KPLC, none has been cancelled to date, but one has been renewed on different terms, one has expired and one has had seen changes to its original tariff. In August 2001, Iberafrica expressed its interest to both ERB and KPLC to negotiate a second PPA (as per the Electric Power Act such a request must be initiated three years before license/PPA expires). Negotiations commenced at this time. KPLC and Iberafrica reached agreement on tariffs; however, ERB rejected the rates. Thereafter Iberafrica and ERB reached agreement on rates, but KPLC rejected the rates. In December 2002, the new government came to power, and all negotiations were stalled until June 2003 due to changes in ERB, MoE and KPLC staff. In April 2002, Iberafrica reduced the capacity charge of its first PPA by 37 per cent. This was not a renegotiation per se, but a voluntary act on behalf of the firm to demonstrate its commitment to a second PPA.²¹⁹ In September 2003, Iberafrica reduced its capacity charge again—this time to 59 per cent of the original PPA agreement. Finally, when renegotiations recommenced they culminated in agreement on a second PPA (for a duration of 15 years) in August 2004, in which the capacity charge agreed was 50 per cent that of the original PPA.

Westmont also requested a second PPA, but the firm and KPLC could not agree on a tariff. As a result, Westmont did not pursue any formal procedure with ERB. In August 2004, with the completion of its seven year PPA, Westmont ceased operating. The barge-mounted gas turbine was retired thereafter. There was some speculation that the plant would be bought by KenGen in 2005, but this did not happen, and instead the state-owned generation company is pursuing other new generation options. In the case of OrPower4, as described in detail in section 5.9.2, the tariff for the second phase, approximately 40 MW, was ultimately renegotiated (to be lower) with negotiations only concluding in 2006, eight years after the original PPA was signed.

Suffice it to say that Tsavo, the project that has been characterized as meeting with the greatest success, is the only project that has seen no changes to its contract terms.

²¹⁹ Contrary to popular press reports, Iberafrica did not amortize its plant over the seven years of its first PPA due to this voluntary reduction in 2002.

5.9.4 Public perception and its consequences²²⁰

The IPPs have generally been perceived as expensive, i.e. more expensive than KenGen. To quote one press report, “compared to state-owned KenGen, which sells its power to KPLC at Ksh 1.76, IPP rates have been seen as a massive rip off [to] the power utility” (*Westmont Bows out of Power Deal* 2004). There are reports in the press of Energy Minister Mr. Ochiilo Ayako indicating that he will continue a sustained campaign for cheaper power by taking on the IPPs and the contracts that have been a “heavy burden to the economy” (Githahu 2004). Owners have also been portrayed as opportunistic, profiting from Kenya’s drought situation and poor investment climate. References to IPPs as being enemies of Kenya have even been made by public stakeholders. Absent from these portrayals has been an accurate description of the state’s inability to finance and build competitive plants within a short timeframe. Initially few IPP owners countered the stereotypes, with the exception of Tsavo. Tsavo has also developed a US\$1 million community development fund, disbursing US\$50,000 annually (over the 20 year PPA) to benefit environmental and social activities in Kenya’s Coast Region. It should also be noted that while less publicized Iberafrika also has a social responsibility programme.

The public campaign has contributed to bringing about a reduction in Iberafrika’s and OrPower4’s tariffs. It also may have contributed to the halt in IPP development until the end of 2005, when KPLC announced that it would tender for a 80 MW BOOT.

5.10 Conclusion

The IPP experience in Kenya is interesting in a number of respects. Despite representing a difficult investment climate (e.g. an aid embargo and no sovereign guarantees available), foreign investment was made in IPPs. Initial stop-gap IPPs were understandably expensive, with wholesale tariffs more than three times KenGen’s. High prices are attributed to the fact that plants were procured during a drought, under severe time pressures, with a truncated tender process. Furthermore, with PPAs of only seven years duration, investors had little time to extract returns. In the second wave of IPPs, projects were tendered under international competitive bid standards. The result was significantly cheaper power than the first wave, with wholesale tariffs appearing to be competitive with KenGen’s. During this second wave, Iberafrika (one of the initial stop-gap IPPs) also halved its capacity charge in its negotiations for a second PPA, and OrPower4 agreed to reduction in the tariff for its additional 36 MW. In the end, Kenya experienced a fairly positive development outcome. The requisite power was supplied, albeit initially at a high rate to the country and consumer. Later, prices became more competitive. Throughout, however, Kenya has experienced significant devaluation of its

²²⁰ Although this thesis has not surveyed the public at large, it has followed general press accounts and parliamentary debates related to IPPs, which are seen as a proxy for the general public.

currency. Between 1990 and 2003, the Kenyan Shilling depreciated more than 300 per cent. Although the currency depreciation has largely abated over recent years, considering that all the Kenyan PPAs are denominated in US dollars, more potential change could weigh heavily.

As for investment outcomes, in the first wave, it is believed that investors fared well given the high tariffs charged. In the second wave, outcomes appear to have been positive, but more modest. All deals (in both the first and second waves) have held, with minor modifications as noted in the case of OrPower4, which is a positive indicator for investment outcomes. As one sponsor indicated, “returns could have been higher, but we do have a good relationship with the off-taker and an acceptable return for our investors.”

Situating Kenya's IPP experience in the context of the World Bank led Energy Sector Reform and Power Development Project goes a long way in explaining how and why investments unfolded as they did, viz. failure to comply with conditional lending terms led to a delay in new plant, which in turn necessitated the stop-gap IPPs. With the Government of Kenya finally assenting to conditions by the end of the decade, a series of reforms were set in motion, including more IPPs and a regulator, with the reform plans supported by a number of international consultancies. Also, in this second wave of IPP development, the World Bank's private sector finance arm, the IFC, took an equity stake in Tsavo and was instrumental in arranging debt. IFC is credited with helping Tsavo to resist pressure from the government after normal hydrological conditions returned, when an attempt was made to renegotiate tariffs, thereby keeping the obsolescing bargain at bay. IFC also is cited as among the factors that helped convince the American powerhouse Cinergy to invest in the project, i.e. it was reassured by the multilateral presence. OrPower4, which was also part of this second wave, obtained a MIGA guarantee, and although the MIGA guarantee has not been invoked, the threat of MIGA's involvement, following resistance by the government to honour the contract, may also be counted as among strategies to ward off the obsolescing bargain.

Furthermore, the regulatory board, which was among the many conditions of the Energy Sector Reform Power Development Project left its mark on the projects. Inaugurated in 1998, after PPAs with Westmont and Iberafrika had been signed, ERB was noticeably absent from the first wave. The Board was, however, able to apply pressure on Iberafrika as it negotiated its second PPA and may be credited with helping to reduce capacity charges. ERB oversaw Tsavo's development from start to finish and has also been intricately involved in OrPower4. It maintains an important tariff setting function. Despite these achievements, ERB's institutional memory and capacity have been undermined by changes in personnel: in the six years of its operation, it has had five different chairmen (all appointed by the President) and numerous board changes.

Although one may easily look to the World Bank project to explain outcomes, this thesis has raised a number of additional important factors that explain the evolving balancing act,

most notably the nature of the project partners. Malaysian-based Westmont had no prior experience in Africa. Equally un-experienced in Africa was Ormat, an USA/Israeli based firm. These two companies opted not to engage local partners. Westmont has since left after it failed to reach agreement on a second PPA. Ormat (through project company OrPower4) has developed only 12 MW, or just 10 per cent of the maximum size specified in its contract, although recent agreements, which saw the firm reducing its tariff, are now leading to the development of a further 36 MW.²²¹

In contrast, Iberafrika had a local partner as a shareholder. Furthermore, Union Fenosa, the dominant shareholder in Iberafrika, also had additional projects in Kenya's IT sector. Tsavo had no local partner, but IPS, which jointly holds 49.9 per cent of the equity with Duke, was incorporated in Kenya in 1963 and therefore has extensive country experience. The Iberafrika and Tsavo plants have fared significantly better than Westmont and OrPower4 in terms of contracts, total generation contribution and ultimately public perception. Iberafrika negotiated a second 15 year PPA, and Tsavo provided a third of the country's thermal/geothermal generation between 2001 and 2003, helping the country to avoid more costly emergency generators. Tsavo has also made a good name for itself through its US\$1 million community development fund. Finally, noteworthy in the context of project partners is the role that IPS and Globeleq, both characterized as more development-minded firms, are playing in Sub-Saharan Africa. As European and American based firms such as InterGen and AES²²² retreated to their home markets, IPS and Globeleq stepped in to fill the development gap, picking up majority stakes in Egypt's Sidi Krir (682 MW), Tanzania's Songas (180 MW) and Uganda's Bujagali (250 MW).²²³ While motivated by commercial interests, both Globeleq and IPS also have a larger appetite for risk and a commitment to emerging markets. It should, however, be reiterated here that Globeleq is in the midst of selling off its entire portfolio of generation assets, with the exception of those in Sub-Saharan Africa, as the firm prepares to concentrate in greenfield development. Although recent trends pointed to the fact that African IPPs might be led by these types of firms, Globeleq's exit leaves another question mark. It may be that more development-minded firms, more third world multinationals or potentially even more domestic capital will ultimately fill the void.

While the existing IPPs appear to be here to stay (save Westmont), future development remains uncertain. Until the end of 2005, it appeared that the country had returned to public sector financing of plants, including via concessionary loans. Stakeholders at KPLC and

²²¹ As highlighted in section 5.5, OrPower4 has, however, out-performed its IPP counterparts, recording the highest availability, utilization and relative contribution to generation.

²²² AES is, however, once again expanding its operations into emerging and developing markets, including in 2006: greenfield investment in Bulgaria, Jordan, Chile, Panama, India, Indonesia and Vietnam (AES Corporation 2006:13).

²²³ IPS and CDC/Globeleq have also maintained shares in Cote d'Ivoire's Azito IPP since the inception of the project in the late 1990s, with IPS holding 23 per cent and CDC/Globeleq, 11 per cent.

KenGen indicated, however, that such funding was limited and slow to materialize. KPLC subsequently invited bids for an IPP for an 80 MW diesel plant. Most recently, Kenya has once again engaged the private sector to supply emergency relief for the persistent drought. KenGen's IPO of 30 per cent of its shares may further change the dynamics of the electricity market, as could the creation of an independent transmission company. Existing investment is not, however, sufficient to meet the latent power needs in Kenya, where only 15 per cent of the population has access. Creating and maintaining a sustainable balance between development and investment outcomes is Kenya's challenge as it seeks to attract new investment.

Chapter 6

Tanzania's Experience with IPPs

6.1 Introduction

Unlike many elements of Tanzania's reform plans in the 1990s, such as establishing a regulator, restructuring the sector, and privatising the utility, the introduction of IPPs is one of the few pieces that materialized. Tanzania's Electricity Supply Industry, characterized by persistent state-ownership and control, has been transformed by the addition of two IPPs. Prior to the inception of IPPs, nearly 80 per cent of power was provided by hydropower; in contrast, between 2002 and 2006, thermal power accounted for about 60 per cent of generation, which was almost exclusively generated by IPPs.²²⁴ Benefiting from new thermal capacity, Tanzania was among the few East African countries able to avoid substantial load shedding. However, in early 2006, drought conditions eroded Tanzania's hydro capacity beyond what the IPPs could provide, and the country resorted to extensive load shedding in February 2006, which continued throughout all of 2006, amounting to approximately 100 MW.²²⁵

Tanzania is a particularly important case for understanding IPP development and investment outcomes for Africa. Notable aspects of Tanzania's IPP programme include: IPPs making extensive contributions to the ESI, the Government of Tanzania's early efforts to adopt reforms, the major contribution of IPPs to reduce load shedding, the controversial nature of the IPP costs and development process, and the Government of Tanzania's (GoT) intervention to assist TANESCO, the state utility, with its monthly payments. Tanzania's IPP experience also offers the opportunity to examine the role of different stakeholders in the IPP process, including government and private sponsors—both local and foreign—together with the involvement of multilateral development institutions, such as the World Bank. Additionally, the Ministry of Energy and Minerals (MEM) is considering developing additional IPPs.²²⁶

Over 30 interviews were conducted with more than 20 stakeholders in January, February, August, November and December 2005 in Dar-es-Salaam, Washington D.C. and via teleconference in London. Interviews were followed by email correspondence to clarify

²²⁴ Between January and May 2007, the latest date which this thesis recorded, IPPs/thermal power accounted for only about 20 per cent of total generation due to the return of normal hydrological conditions. There has been no load shedding recorded in 2007.

²²⁵ Tanzania's neighbours (Uganda, Burundi, Rwanda) all resorted to load shedding between 2002 and 2005, a period which coincided with severe drought in the region. Tanzania was able to make up this difference with IPPs (although outages due to the failure of transmission and distribution were frequent). In early 2006, under continued drought conditions, hydro shortfalls reached larger levels than IPPs could make up, and Tanzania also began load shedding. Load shedding reached 12 to 18 hours per day in many areas of the country in February 2006 and continued throughout the year, despite IPPs running at full capacity.

²²⁶ References to both Government of Tanzania (GoT) and Ministry of Energy and Minerals (MEM) are made repeatedly throughout the paper. While MEM is part of GoT, it should be noted that explicit reference to GoT implies that stakeholders may have included, but were not limited to those, in MEM.

discussion points, with the last review of data conducted in May 2007. Stakeholder interviews included present and former directors and managers at Orca Exploration, IPTL, Songas, EWURA, MEM, PSRC, TPDC, VIP, TANESCO, NETGroup Solutions, Sida, and the World Bank. *Due to sensitivity of data, the names of stakeholders, who have been the primary source of data for this thesis, have largely been left out of the discussion; most stakeholders are only identified, if at all, by organizational affiliation in the text. As a result, much of the data, which forms the basis of this Chapter, is not cited. In certain instances, however, where stakeholders have indicated their willingness, citations do include names and the designation of "per com" for personal communication.*

6.2 Tanzania's two main IPPs: IPTL and Songas

Tanzania developed two main IPPs over the last decade.²²⁷ Together, they contribute approximately 300 MW, or about one third of the country's present generation capacity of 1005 MW (inclusive of emergency power as of May 2007). In terms of energy sold, as of 2006, Tanzania's IPPs were contributing over half of the electricity generation, and represented the main source of thermal (non-hydro) capacity. Starting in 2007, however, with the resumption of normal hydrological conditions, IPP contribution dropped to about one third of total production.

Independent Power Tanzania Limited (IPTL) was the first IPP to begin to sell electricity to the national electric utility. An independently negotiated IPP among Malaysian investors, a local Tanzanian firm and the GoT, the construction of IPTL was completed in 1998, but IPTL started producing power only in January 2002, after a three year delay resulting from a dispute over construction costs and related capacity payments. The 100 MW diesel plant consists of 10 medium-speed units of 10 megawatts each, which presently run on imported HFO. Eventual conversion to domestic natural gas has been intended for IPTL since its original PPA and is expected in the near-term.

²²⁷ Several small self-producers have also sold power to TANESCO for many years, including Tanwat (2.5 MW), Kiwira Coal Mine (6.0 MW)—which were the first two IPPs—and Kilombero Sugar (2.5 MW). However, they sell only small amounts of excess power, and thus are not treated within the scope of this study. Kiwira's proposed additions will be treated below together with the recently commissioned Mtwara Energy Project.

Table 6.1: Technical specifications for Tanzania's IPPs

Projects	Size (MW))	Technology /Fuel	Contract type	Contract Years	L Capacity utilization target ²²⁸	Time from tender to operation
IPTL	100	Diesel generator/ HFO	BOO	20	85%	1994 ²²⁹ - 2002
Songas Project	180	OCGT/ Natural gas	BOO	20	91%	1993-2004

Songas, Tanzania's second IPP, commenced operations in July 2004. The 180 MW natural gas-fired plant consists of six open cycle gas turbines, which are run on natural gas sourced from the domestic off-shore Songo Songo gas field (four of the turbines were pre-existing and converted to run on natural gas). The IPP is part of a larger gas project, which included: refurbishment and development of offshore gas wells; installation of a gas processing facility; construction of a 232 km pipeline to Dar es Salaam; conversion of an existing 115 MW power station (Ubungu) from jet fuel to natural gas, consisting of four turbines, as mentioned above; the provision of 65 MW additional capacity at the Ubungo station; the supply of gas for the Twiga cement plant at Wazo Hill; and the development of a larger commercial market for gas.²³⁰ The Songas project benefited from loans from the World Bank's IDA, EIB, and Sida and involved numerous private sector companies and more than 20 contracts. Development of Songas took more than a decade.

²²⁸ Capacity utilization targets are set in the power purchase agreements.

²²⁹ There was no formal tender for IPTL, rather IPTL was a result of a bilateral agreement with Malaysian investors and local Tanzanian investors.

²³⁰ As of May 2007, the project was supplying gas to 16 additional firms, namely: Aluminium Africa, Bora Industries, Karibu Textile, KIOO Limited, Lakhani, Mukwano, Murzahi 1, Murzahi 2, Murzahi 3, Nida Textile, Tanzania Brewery Limited, Tanzania-China Friendship Textile, Tanzania Cigarette Company and Urafiki Textile, and two additional power producers (Aggreko, and Dowans).

Table 6.2: Financial specifications for Tanzania's IPPs

Projects	Project Cost (US\$ million)	Total equity (%)	Total debt (%)	Local equity	Local debt	Int'l private debt	DFI financing
IPITL	\$ 127.2	\$38.16 (30%)	\$89.04 (70%)	US\$1 land lease + in kind (PPA & guarantee, 30%)	-	\$89.04	-
Songas Project without expansion (115 MW)²³¹	\$266	\$60 (23%)	\$206 (77%)	\$4 (TDFL) \$4 (in kind by TANESCO & TPDC) ²³²	-	-	\$206
Songas Project expansion (65 MW)	\$50	\$50 (100% ²³³)	-	-	-	-	-

It should be noted at the outset of this Chapter that the majority of the analysis is focused on IPITL and Songas and the years leading up to 2006. Since there has been a flurry of private power activity, including several emergency power plants, the Mtwara Energy Project and units at Kiwira Coal Power Limited. Although as of yet, only limited capacity has actually been brought online. A brief description of these developments is provided immediately below for general reference. New publicly sponsored plants will be discussed in section 6.3.3.

Emergency power

At the end of 2006, with persistent drought conditions, the GoT engaged two emergency plants (with short-term contracts of approximately one year): a 40 MW generator provided by Aggreko and a second 40 MW generator provided by a subsidiary of Alstom. The Aggreko plant is using gas from the Songo Songo gas field at a price of US\$2.17/ Million British Thermal Unit (MMBtu) (*Tanzania* 2007b:4). In addition to these two emergency plants, agreement was struck with Richmond, a special purpose vehicle formed in 2006 to provide 100MW of emergency power, for two years starting in September 2006 (20MW) followed by

²³¹ Songas project costs include refurbishment of gas wells, a new gas processing facility, pipeline construction and fuel conversion of the existing power station (Ubungu), in total amounting to US\$266 million, and an additional US\$50 million for expansion in terms of two additional turbines (total 65 MW) and related infrastructure. The expansion was financed entirely by equity. A rough estimate for the electricity generation component would be 40 per cent of project costs or US\$130 million, based on US\$35 million for refurbishment and fuel conversion of existing turbines, US\$45 million assumed loans on existing turbines, and US\$50 million for expansion. It should be noted, as will be described in detail in the text, that there was considerable evolution in terms of the planned capacity for the plant, from 60 MW to the current 180 MW.

²³² Tanzania Development Finance Company Limited (TDFL).

²³³ TANESCO is currently pursuing refinancing of the Songas expansion for a split of 75:25 debt/equity, which would reduce capacity charges.

the balance (80MW) by February 2007, which was safeguarded by a government guarantee. The first 20MW (of the 100 MW) was brought online in October 2006, fuelled with natural gas supplied by Songo Songo, however, only after the government advanced Richmond funds (as neither the parent company, which it turns out is a publisher, with no prior experience in power supply, nor the subsidiary, operating from a residential address in Houston, had money to lift the generators). Dowans Holdings, based in the UAE, has since bought the plant and taken over the contract. The remaining 80MW have yet to be brought online, and there is speculation that the additional capacity may be cancelled. Meanwhile although Tanzania's Preventative Corruption Bureau (PCB) recently issued a statement denying corruption in the Richmond case, there is general public dissatisfaction with the PCB's pronouncement and with how the plant came into existence. It is possible that further investigations may be launched to answer the many outstanding questions.

Mtwara Energy Project

In May 2007, Artumas Tanzania (Jersey) Limited (ATJL) brought online 12 MW, which is being fed by the Mnazi Bay gas field.²³⁴ Also known as the Mtwara Energy Project (MEP), this project dates to 1994, when Tullow Oil was selected (via a selective tender) to develop the Mnazi field. In the decade that followed, however, no developments took place, with Tullow citing poor economics of the project as the main stumbling block. In 2003, the Canadian-based Artumas (which had also been involved in the selective tender of 1994) expressed its interest once again to develop the field and related gas and power infrastructures.²³⁵ Subsequently, a Production Sharing Agreement was signed by ATJL, the GoT and Tanzania Petroleum Development Corporation in May 2004. The firm re-entered an existing, unfinished gas well to drill it to acceptable levels in May-June 2005. In July 2005, the parent company, Artumas Group, sought to raise additional funds by listing its shares on the Oslo Stock Exchange as well as by engaging the Dutch Development Company (FMO) in a 20 per cent equity share in ATJL. Seismic studies, the drilling of two more gas wells, and the purchasing 6 x 2MW gas engines to serve the isolated administrative regions of Mtwara and Lindi (on the southern border of Tanzania and Mozambique) followed.

Previously Mtwara and Lindi were served by TANESCO at US\$0.42/kWh using old diesel engines with less than 50 per cent reliability, compromised by (1) fuel supply challenges;

²³⁴ ATJL, which is jointly owned by Artumas Group (80 per cent) and FMO (20 per cent), is the 100 per cent shareholder in four subsidiary companies: Artumas Group and Partners Gas Limited (AG&P Gas), Artumas Group and Partners Power Limited (AG&P Power), Umoja Light, and Artumas Energy Tanzania Limited (AETL). AG&P Gas oversees the development of the Mnazi gas field; AG&P Power is responsible for developing the power infrastructure; Umoja Light will run the transmission and distribution component, and AETL provides management services to each of the subsidiaries. For the sake of simplicity, however, ATJL alone is used in the discussion above.

²³⁵ At the time, however, in 1994 Artumas was known as Tonardo Resources.

(2) shortage of cash; and (3) frequent breakdowns. In July 2006, ATJL signed an interim PPA to act as an IPP and sell power to TANESCO at US\$0.1195/kWh for the first year. After a year of operations, TANESCO is expected to lease the distribution infrastructure to ATJL, and ATJL will manage an isolated franchise area for 20 years (with less or no subsidy). Negotiations are still on, thus the project has not yet reached financial closure. Sponsors have, however, indicated that negotiations are due to wrap up in 2007 with financial closure expected by early 2008, at the latest. At this stage, apart from interim measures there is no bankable document or long-term agreement. It should be noted that there has been considerable disagreement about the demand of the Mtwara and Lindi regions, with some reports indicating demand of up to 300 MW and others as little as 9 MW. Project sponsors meanwhile have stated that they have identified approximately 90 MW of incremental industrial load, which will be the focus of its business development efforts in the near-term.

Kiwira Coal Power Limited

Kiwira Coal Power Limited presently supplies excess generation from a 6MW plant to the grid. In 2006, the company expressed interest in feeding a further 200MW to the grid. Fifty MW were expected by December 2006, followed by another 50MW in June 2007, and 100 MW in December 2007, however, the firm has not yet secured (as of May 2007) the funds to finance the transmission line from Kiwira to Mbeya (a distance of approximately 135 km). Although the firm claims to have sufficient funds to develop the (first) power project, no work has commenced due to the lack of transmission funds.

6.3 Power sector reform context

6.3.1. The start of reforms

The initiation of electricity sector reforms in Tanzania was catalysed by a combination of macro-reform priorities, national energy policy, electricity sector conditions, and international donor priorities. In 1992, the government expanded macro-economic reforms started under structural adjustment in the mid-1980s²³⁶ to include sector-focused objectives. Also in 1992, the first National Energy Policy, which included intentions to involve the private sector in development of the energy sector, was enacted. In the same year, facing a drought-induced electricity crisis and extensive load shedding, the government lifted the state utility's monopoly on generation to attract private generation and alleviate shortages, which paved the way for the country's two IPPs, discussed in detail in subsequent sections. The reform imperative was

²³⁶ Tanzania's World Bank and IMF supported structural adjustment began with the Economic Recovery Programme (ERP) in 1986-1989, following on two earlier national economic programmes.

reinforced by changes in World Bank lending policy, as spelled out in Chapter two (World Bank 1993a).

6.3.2 Early efforts to commercialize and restructure TANESCO

The driving model of Tanzania's electricity reform was originally aimed at restructuring and unbundling the electricity sector for eventual privatization.

At the time of initial reforms, TANESCO, the national utility, was already corporatized, with the firm operating under Tanzania's Company Ordinance Act since 1931. During the 1970's to mid-1980's the national utility functioned adequately, yet toward the end of the 1980's utility performance deteriorated (Katyega 2004:9). Despite its corporatized status, from the early 1990's, the firm recorded poor technical and financial performance, making status quo operation increasingly untenable.

In 1992, the utility was forced to shed 130 MW (Tanzania Electric Supply Company Limited 1992:5) due to lack of generation availability. By 1994, load shedding amounted to 100 MW, still nearly one third of maximum demand in the grid system (World Bank 2001:4). Combined technical and non-technical losses amounted to 20 per cent in 1992 up from 15 per cent a decade earlier. Losses reached a high of 28 per cent in 2001, after briefly improving between 1995 and 1998 to 12-14 per cent (Katyega 2004:11). TANESCO was unable to cover its operation and maintenance costs and debt service repayments from its revenue collection, which fell during the 1990's. In the early 1990's, the average tariff was below costs due to reluctance to increase tariffs during prescribed currency devaluations. However, efforts were made to correct the trend, and the average tariff reached a strong position by the mid-1990's, a situation that continued throughout the decade (Katyega 2004:16). Additionally, TANESCO faced difficulties in enforcing payments for services and arrears. Debt collection days deteriorated from 203 days in 1990 to 413 days in 1999 (Katyega 2004:16). Particularly difficult were collections from public institutions (Marandu 2001:37). With diminished revenues for maintenance, outages and distribution losses increased during the same period (Katyega, Marandu et al. 2000:4; Katyega 2004:16).

Efforts were made to commercialise and improve TANESCO's operations in the 1990's via the support of the World Bank Power VI project and the World Bank's Energy Sector Management Program (ESMAP) Power Loss Reduction Study and Technical Assistance to TANESCO Project (World Bank 2003b). However, despite these efforts (including introduction of prepayment electricity meters, loss reduction measures,²³⁷ and contracting out services), TANESCO remained in a weak financial position by the late 1990's, and utility performance deteriorated to unprecedented levels. It should be noted in this context that Power

²³⁷ Improvements in losses in the mid-1990's, referenced above, were a result of an ESMAP Technical Assistance project.

VI, similar to Kenya's Energy Sector Reform and Power Development project, tied the development of the 180 MW Kihansi Hydropower station to power sector reforms, including plans for restructuring the sector and introducing of private participation into both power and natural gas development.

In 1997, TANESCO was put under the President's Parastatal Sector Reform Commission (PSRC), as discussed in section 2.5.1, created in 1992 to oversee the privatization of state-owned enterprises in industry and manufacturing. Formal intentions to restructure the power sector to achieve unbundling and eventual privatization were spelled out in a 1997 letter of intent to the World Bank, including restructuring plans to unbundle TANESCO into two generation companies, one transmission company, and two distribution companies.²³⁸ A 1999 Cabinet decision outlined an electric industry policy and restructuring framework to move ahead on restructuring and unbundling in preparation for privatisation, which as previously described, was informed by a study tour through, among other Latin American countries, Argentina, funded by Sida and organized by the World Bank. Among the next steps was engaging the international consulting firm, Mercados Energeticos, as noted earlier, to assist with a plan for unbundling, privatization and the introduction of competition.

6.3.3 The management contract and future reforms

Seeking more dramatic financial turn-around in preparation for privatization, the MEM issued a request for proposals for a management contract for TANESCO in 2001, which was won by the South African company, NETGroup Solutions in 2002.²³⁹ It should be noted that the management contract, in contrast to the Mercados work, which was funded by the World Bank Privatization and Private Sector Development Project, did not fall neatly into one World Bank credit; instead, for the management contract, Sida funds were administered through a World Bank trust fund.

Under NETGroup Solutions and with the support of the GoT, TANESCO doubled revenue collection from US\$11 to over 22 million per month between May 2002 and May 2004 (Davies 2004, and unpublished TANESCO data). These gains were achieved mainly through enforcing collections and arrears payment, with particular attention focused on the large arrears of public institutions. Enforcement has included high profile service disconnections and collections from the police, the national post offices, and even the entire island of Zanzibar in addition to private customers.

In 2004, the management contract was extended for two years, through the end of 2006. The extension expanded the mandate of the consultants to include technical turn-around in

²³⁸ Tanzania's commitment was outlined in a Letter of Sector Development Policy written to the World Bank in advance of the Songo-Songo gas-to-electricity loan. Such letters are common requirements to World Bank lending.

²³⁹ Eskom of South Africa was an unsuccessful bidder.

addition to financial-turn around, specifically including electrification and reliability targets. When the contract finally reached its end in 2006, significant revenue gains for TANESCO (albeit concentrated in the first part of the contract) continued to be cited as among its achievements. Also, an achievement was the track record of working with GoT. The management contract failed, however, to bring more lasting changes in the financial and technical operations of TANESCO. Stakeholders cite financial constraints external to the contract—namely poor hydrological conditions, costs of IPP power, and insufficient tariff rates—to have limited TANESCO’s ability to make investments to improve electrification or reliability (Ghanadan and Eberhard 2007:30-33).²⁴⁰

In a few short years, TANESCO went from being optimistic about prospects for financing service investments from utility revenues to crisis conditions where TANESCO urgently needed additional funds and emergency supply to account for increasing generation costs, supply shortfalls, and load shedding. These conditions hindered the performance of the management contract and the ability to make necessary investments in reliability and electrification. The prospect of making up the difference of increasing generation costs via large tariff hikes, raises the question of affordability, namely how high tariffs the economy and society can bear. Residential rates have already tripled in the last three years, and access remains only 10 per cent overall.

Although initially the MEM was considering several different options for TANESCO at the end of 2006, including an extension of the contract and standard reform steps as recommended by Mercados, TANESCO ultimately reverted to public control. Privatization no longer appears to be a near-term goal, and as of end-2005, TANESCO was taken off the list of utilities specified for privatization. Management is being decentralized, with the re-introduction of administrative zones and corresponding customer services. GoT is also facilitating a 300 billion Tanzanian shilling loan (equivalent to approximately US\$230 million based on May 2007 average exchange rate) to TANESCO as part of a three year Revenue Recovery Plan, with the sole purpose to commercialize TANESCO and improve the quality of service—notably goals under the management contract. The entire loan is being syndicated domestically, with the first tranche of approximately US\$100 million made available in 2006. Stanbic Bank of Tanzania is the lead arranger; the Government of Tanzania is providing a government guarantee, but in contrast to the past several decades, no World Bank involvement has been seen to date, and none is expected.

²⁴⁰ One important aspect of restructuring and institutional development has been efforts to develop a Rural Energy Agency and Rural Energy Fund (REA/REF). Legislation was passed to establish the REA/REF in 2005 although as of end-2006 it is still not functional. The REA/REF is intended to complement commercialization efforts and consolidate donor activities, as non-commercial rural electrification will be separated out from TANESCO operations and all donor projects and funding will operate through the REA/REF.

Meanwhile, in terms of new generation, TANESCO plans for new plants, although delivery continues to be a problem. Initially 105 MW of new TANESCO generation was expected at Ubungu (60 MW) and Tegeta (45 MW) in April and December 2006, to be fuelled by gas from Songo Songo. Due to delays in these two projects, however, Aggreko and a subsidiary of Alstom provided 40 MW each, under short-term contracts. Richmond provided 20MW, also under a short-term contract. The two TANESCO plants that were planned are still expected on line, albeit later and in a slightly different form and timeframe. A permanent 100MW Wartsila gas turbine is currently under constructed at Ubungu, with commissioning expected in September 2007 and to be fuelled by Songo Songo. A further 45MW are expected at Tegeta, with 50 per cent funded by a grant from the FMO's Development Related Export Transactions Programme and 50 per cent via a loan from FMO. This plant is now expected to be commissioned in July 2008. A further state-led initiative, which has been in the planning stages since the mid-1990s, but for which attention increased in 2006, is the interconnector to link Tanzania with the Southern African Power Pool (SAPP).

In following the theme of power sector reform through this thesis, it is important to reiterate on the one hand the extensiveness of the World Bank's involvement and promotion of the standard model, which also found its champions within the country, and on the other hand, the significant deviation from any such prescribed model, as also evidenced in Kenya.

6.3.4 Structure of the sector

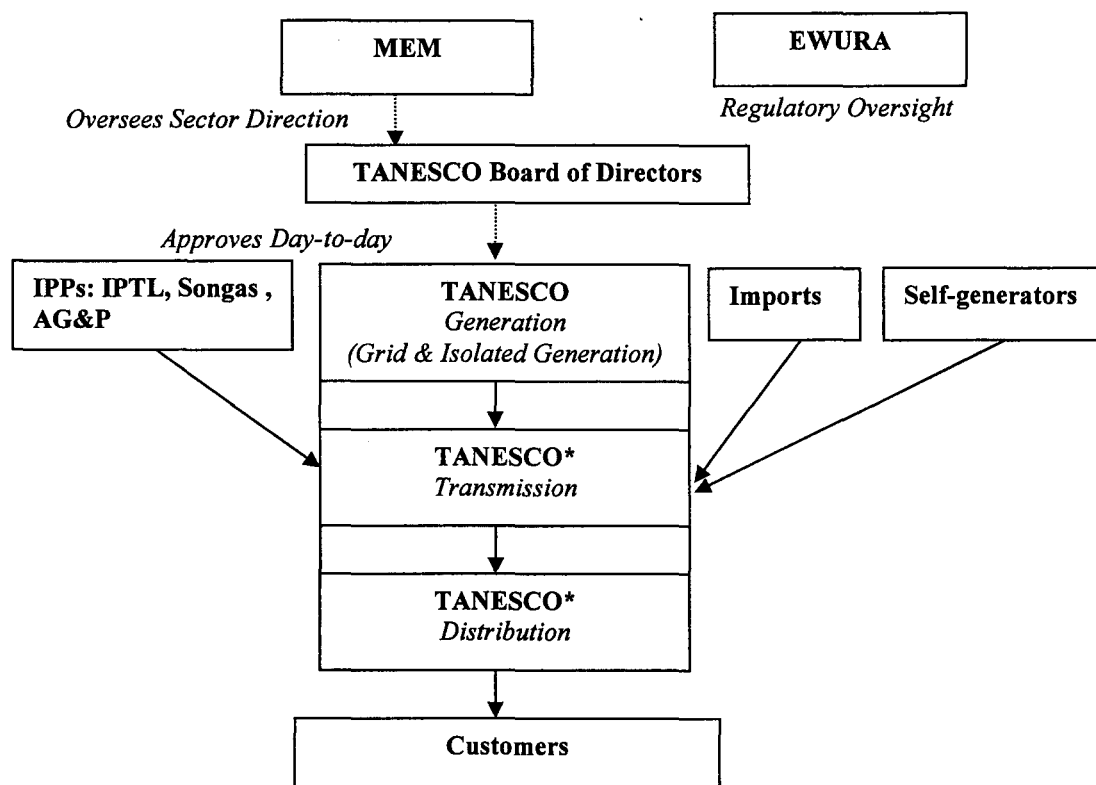
After a decade of reform efforts, TANESCO remains a vertically integrated utility but no longer holds a monopoly in generation. The two main IPPs, IPTL and Songas now contribute to generation, in addition to TANESCO's state-owned hydro and small diesel facilities. Small amounts of imports and self-generators also contribute to the ESI. Furthermore, as noted previously ATJL commenced natural gas based power generation for the southern-east franchise of Mtwara and Lindi in March 2007.

MEM oversees sector direction. The TANESCO Board of Directors is appointed by the MEM and approves the day to day operations of TANESCO. Since mid-2006, Tanzania has also seen the emergence of an independent regulator. Although legislation was passed to establish the Energy and Water Utilities Regulatory Authority (EWURA) in 2001, EWURA only became operational in mid-2006, with the following mandate: licensing, tariff regulation and quality of service regulation of the electricity, water, petroleum and natural gas sectors.²⁴¹ Although the terms of any future IPPs may be subject to EWURA's review, all the country's existing contracts, including that negotiated with Richmond fall outside its purview, and in its

²⁴¹ Debates over the structure of the utility regulatory agencies and their relation to existing oversight bodies and line ministries caused delays in the development of EWURA and the other utility sector regulators.

founding documents, the regulator is discouraged from challenging any such agreements (United Republic of Tanzania 2001: 7(2,50)).

Figure 6.1: Structure and oversight of Tanzania's electricity supply industry



6.4 Development of Tanzania's IPPs

6.4.1 Early gas discovery, drought and gas-to-electricity plan

Gas was discovered in 1974 at Songo Songo.²⁴² The initial plan was to harness gas for fertilizer production. GoT partnered with Agrico, an American company, in 1981, to form the project company Kilwa Ammonia and Urea Company, KILAMCO (51 per cent GoT, 49 per cent Agrico).

By 1989, with little to no progress made, negotiations collapsed. Failure to close the deal is attributed in part to the poor investment climate at the time, with little support for foreign direct investment.²⁴³ Meanwhile, the idea to use gas for power had long been considered by MEM, but there were insufficient public funds and private investment was not forthcoming. MEM began a more focused evaluation of the gas-to-power option after the Agrico deal fell

²⁴² Songo Songo 1 (SS1) was drilled and funded by AGIP, which had a Production Sharing Agreement with the GoT; SS2, SS3 and SS4 were drilled by TPDC using Government of India financial and technical assistance, which had been extended to the GoT; the rest of the wells (SS5, SS6, SS7, SS8, SS9) were drilled in the 1980s by TPDC.

²⁴³ One stakeholder characterized the investment climate as follows: Tanzania was emerging from a command economy; firms were (legitimately) concerned with nationalization; the currency was not convertible and firms were not able to repatriate profits.

through. By 1991, it had been determined that gas-based power generation was the next least-cost to hydropower and quicker to develop than other sources, which became a corner stone of the Power System Master Plan of the same year.

Around the same period, in the early 1990s, the GoT was approached by Ocelot (today Orca Exploration), a Canadian-based gas company, with a proposal to develop Songo Songo. Among the options that Ocelot and GoT discussed were LNG development, a gas pipeline for export to Mombasa, and gas for domestic use. Two different plans were endorsed by consultants, but no conclusion was reached at this early stage.²⁴⁴

On the heels of Ocelot's initial proposals, starting in 1992, the country experienced a major drought. The MEM in turn sought emergency measures to plug its power shortage. In November 1992, Sida, Tanzania's largest bilateral energy donor, provided funds for TANESCO to procure approximately 40 MW of power (two 18 MW ABB GT 10A open cycle turbines, which ran on jet fuel).²⁴⁵ The turbines were installed at Ubungo. Sida also committed to meeting the operating costs (primarily fuel costs) of the turbines, in the first two years, which amounted to about US\$35 million. It was expected that by the end of 1993, or shortly thereafter, gas from Songo Songo would be available, i.e. before the grant for fuel was exhausted, the country could convert to domestic gas to feed the two turbines (despite the fact that the gas infrastructure had still not been contracted).

With persistent power shortages, and mounting pressure to procure fuel for the Ubungo plant, in February/March 1993, the MEM invited 16 companies, which had experience in gas and power development, to bid for the Songo Songo gas-to-electricity project. According to stakeholders at the MEM, competition for the project was a pre-requisite of the World Bank, which at the time was active in reform proposals for Tanzania's ESI.²⁴⁶

The invitation contained a basic project concept to rehabilitate the existing gas wells (which had been drilled in the 1970s), develop a pipeline to Ubungo, convert and supply two existing (ABB) turbines and add an additional 60 MW (in the form of two additional units),

²⁴⁴ Export of gas and electricity from Tanzania to Kenya was recommended by Hardy BBT Limited and the Songo Songo Gas Development Project (gas for domestic use) was recommended by National Economic Research Associates, based in the U.S.

²⁴⁵ The turbines were a conditional grant to the GoT, but a loan to TANESCO and whoever inherited/bought the units. The book value of these two turbines amounted to US\$15 million on Transfer Date (August 31, 2004).

²⁴⁶ World Bank involvement at the time included the Power VI Programme, as referenced in the previous section, a US\$200 million loan to help rehabilitate the Tanzania ESI, under which the Kihansi Hydropower station of 180 MW would eventually be developed (initially planned for 1995 but came on line in 2000 only). A key provision in the Power VI Programme was that for any new investments to the power sector of greater than US\$5 million the World Bank should be informed—a less stringent condition than that spelled out in the Songas loan agreement which required World Bank approval. The rationale behind this policy, which applies generally to World Bank IDA countries, was to ensure coordination, namely coordination with the World Bank, which was among the largest lenders to the sector.

under a Build Own Operate Transfer arrangement.²⁴⁷ Firms were allowed to form consortia to ensure both upstream and downstream expertise. Among those companies invited were: Enron, British Gas, Amoco and Ocelot.

At the time of the initial invitation, no credit enhancement was provided (i.e. no sovereign guarantees, no escrow accounts) despite a widely perceived poor investment climate and an insolvent utility. Furthermore, firms were given only six months to submit bids with a deadline of August 1993 set by the MEM. It should also be highlighted that the plant size (of 60 MW) was small for international standards.

Due to these limitations (namely, investment climate, time, size), of the 16 invitees, only two submitted bids: OTC, a joint venture between Ocelot and TransCanada Pipelines (a Canadian firm with expertise in power development), and a joint venture of Enron and Andrade Gutierrez.²⁴⁸ In December 1993, the MEM, TANESCO and TPDC met to review proposals, ultimately recommending the OTC bid to the Minister of Energy. The World Bank was consulted in January/February 1994, and OTC was officially awarded the tender by February 1994. By July 1994, negotiations commenced in Dar-es-Salaam with the project company Songas, which was composed of Ocelot, holding a 25 per cent equity stake, and TransCanada, which held the balance of the equity.

As negotiations were gaining momentum, the country experienced yet another drought in November 1994. At this time, additional equity partners were under consideration, including TPDC and TANESCO, which would eventually formalize their stakes in the project by October 1995, together with those listed above. In addition, over twenty different contracts were being drafted to satisfy the requirements of the Songo Songo project participants, and financial closure had not yet been reached. Rather than wait the six months or more before the project was finalized, the MEM sought to install additional emergency capacity at Ubungu.

6.4.2 Persistent power shortages and the emergence of IPTL

It was at this time that GoT began considering, among others, the Independent Power Tanzania Limited (IPTL) project proposal,²⁴⁹ which would ultimately yield an additional 100

²⁴⁷ This project concept would evolve significantly over the decade—from 60 MW to later 150, then scaled back to 115 and eventually to the present 180 MW.

²⁴⁸ Enron put up a proposal but did not submit it in July 1993 (due to a court injunction against the firm). Only two proposals were received - one from the Joint Venture of Ocelot Energy Inc and TransCanada Pipelines Limited, and the other from Andrade Gutierrez. Since the latter was experienced as a road infrastructure construction company without petroleum exploration skills, during the clarification period, and after Enron was cleared by the court of law, Andrade Gutierrez and Enron formed the joint venture and re-submitted their proposal (in a form of clarification addendum) in November 1993 before the negotiations started.

²⁴⁹ Among the other project proposals cited to address the 1994 power shortage is one by an Irish national, Reginald John Nolan, with investment interests in Tanzania since 1986 including through supplying military equipment to the GoT. Also under consideration since the mid-1990s has been an interconnector to link Tanzania to the SAPP.

MW. The IPTL project company was formed between a Malaysian firm, Mechmar (70 per cent), and the Tanzanian firm VIP Engineering Limited (30 per cent).

According to numerous stakeholders, the IPTL deal grew out of genuine South-South collaboration, which was being heralded at the time as an alternative to the North-South donor-recipient model of the previous decades. Within this context, Malaysia was seen as a promising partner, a leading “Asian Tiger”, whose growth could be replicated in other developing countries. Potential investments were earmarked for the transportation sector, but a first priority was given to electricity. At the time, Mechmar had been contracted by CDC to develop a 2.5 MW unit for the Tanwat wattle factory in Tanzania (see footnote 148). The firm also had experience in developing six other biomass plants outside of its home country. VIP had never worked in the power sector, but had considerable experience as a promoter and negotiator for projects.

On November 21, 1994, IPTL submitted a proposal to the GoT. It should be noted that unlike Songas, there was no formal tender. However, with the persistent power shortages the GoT had been seeking a fast-track solution to increase its non-hydro generation capacity. A meeting was convened on December 15, 1994 to address the proposal, attended by the then Permanent Secretary of Energy and Petroleum Affairs, Commissioner of Energy and Petroleum Affairs, Assistant Commissioner of Energy and Petroleum Affairs, Managing Director of TANESCO and other key representatives from the GoT including the Treasury, State House and Attorney General. At this time, both parties (IPTL and GoT) agreed that IPTL could not meet the fast-track power deadline for mid-1995, but that the firm’s proposal might be considered within the context of the country’s long-term power plan.

Instead, through a World Bank facility (that existed as part of the Power VI project) the GoT was able to finance two additional turbines of 35 MW each (two GE LM 6000 open cycle turbines, burning jet fuel). Combined with the previous turbines, this now made up a total of approximately 115 MW at Ubungu, which met the immediate shortage, and IPTL was deferred. As with the previous turbines, it was expected that the GE LM 6000 would be converted to burn natural gas at the earliest possible date.²⁵⁰

6.4.3 The AFUDC and increasing Songas engagement

Meanwhile, Songo Songo negotiations continued. Tanzania Development Finance Company Limited (TDFL) (sponsored by EIB), IFC, DEG and CDC all joined the project company by February 1996. Among the key provisions agreed to later in 1996 was the allowance for funds used during construction (AFUDC) and the escrow account.

²⁵⁰ While the choice of jet fuel as the preferred fuel for the gas turbines is understandable in the light of plans to convert the turbines to run on natural gas within a short time, it can be argued that it was a risky and costly strategy – particularly as the special quality of jet fuel used was otherwise not commonly available in Tanzania. As a result, the fuel bill was unnecessarily high.

In the case of Songo Songo, the MEM sought to engage the project sponsor's equity (before debt) for three primary reasons: to commit the project sponsors up to completion (with the consequence that they lose their equity if they quit prematurely); begin work on refurbishment of wells (rather than await financial closure which was expected to take about two years); and finally, debt funds were not available at the time. To entice sponsors to start development, the MEM offered a nominal interest rate of 22 per cent on all equity (denominated in US dollars) disbursed during construction, also known as the AFUDC. Due to the fact that there were no funds to pay sponsors at that time, it was agreed that the AFUDC would be compounded annually until such time that the project started generating revenues. It was expected that revenues would be generated starting at COD, within a one year period. At COD, the AFUDC would be added to the project capital cost (and repaid through the capacity charge), then sponsors would subsequently earn an annual return on equity of 22 per cent (non-compounded). The AFUDC started accumulating in 1996.²⁵¹

In addition to the AFUDC, sponsors required an offshore escrow facility to cover 100 per cent of target equity contributions ahead of the Transfer Date (TD, i.e. July 31, 2001), as an exit strategy if nationalization occurred prior to construction completion date. The amount in the escrow account was to be reduced to 50 per cent on the 3rd Anniversary of TD i.e. August 1, 2007 and zero on the 6th Anniversary of TD i.e. October 2010.²⁵² The escrow was to be raised through a surcharge on fuel.

6.4.4 IPTL agreement and disagreement

Although Songas was expected to materialize in the near-term, during the same period, negotiations reached completion with IPTL. A PPA was signed between the GoT and IPTL for a 100 MW diesel generator in May 1995, which was expected to be converted to run on natural gas with the completion of the Songo Songo gas-to-electricity project. Standard security arrangements and credit enhancements, as will also be seen in the case of Songas, were sought and obtained. A sovereign guarantee was extended to the project for the full value of the PPA. An escrow account, to be held by the Central Bank of Tanzania, equivalent to between two and four months capacity charges, was also negotiated.²⁵³ These terms differ from those negotiated by Songas, described above, which may be explained by the fact that the MEM never

²⁵¹ It should be emphasized here that neither the AFUDC, nor any of the other credit enhancements extended to IPTL or Songas, is not uncommon, and (especially) in the case of the AFUDC that the terms agreed upon were based on the assumption that the project would be completed in a timely fashion (i.e. COD was expected by June 1999 which would mean an AFUDC of US\$25 million). That assumption proved wrong, and significant interest accrued as it took five more years for the project to reach financial closure and almost a decade before COD, delays that are largely associated with disputes over IPTL.

²⁵² At the moment, the amount in the Escrow Account is US\$2.5 million (with funds having been used to buy down the AFUDC) and will reduce in the same way (as specified above) or if negotiated otherwise.

²⁵³ The IPTL escrow account is in effect a liquidity facility, although it is termed an 'escrow account' by stakeholders. As of May 2007, the escrow account has not been established.

formalized a set of standard IPP terms and conditions and the projects were negotiated by different stakeholders.

Financial closure required another two years, and ultimately involved two Malaysian-based banks (Bank Bumiputra Malaysia Berhad--now Bank Bumiputra Commercial Bank--and SIME Bank) and an informal guarantee by the Malaysian government to the banks that their investment would be secure in Tanzania.

Table 6.3: IPTL project financing, security arrangements and credit enhancements

Project	Estimated project costs	Equity (30%)	Debt (70%)	Security arrangements and credit enhancements as included in PPA		
				Liquidity facility	Escrow account	Other
IPTL	Monthly capacity charges of US\$3.6 million	Return on Equity 22%	Interest rate 8.5%	None (see footnote 253)	Equivalent to 2-4 months capacity charge <i>(as of yet not established)</i>	Sovereign guarantee for value of project (PPA)

The circumstances surrounding the IPTL agreement have been widely debated, even criticized, with numerous stakeholders alleging corruption and/or not due process, namely that officials in Tanzania were paid to sign the contract for power, which was not included in the Power System Master Plan and would make Songas redundant. Such allegations are denied by, among others, local partner VIP and IPTL management itself, who argue that the project emerged from a genuine South-South collaboration with Malaysia, the project was identified as a viable solution by GoT starting in December 1994, and the parties agreed (legally) to terms of the PPA.²⁵⁴

The impact of the IPTL agreement was not immediate. Negotiations with Songas were ongoing and the project company continued to make equity disbursements to fund the development of the project (with an impact on the AFUDC) until 1997. In this year, several things happened. Firstly, IPTL reached financial closure and started construction, with an Engineering Procurement and Construction Contract (EPC) completed with Stork-Wartsila Diesel B.V. of the Netherlands i.e. the plant began to materialize. Secondly, in the latter part of 1997, Tanzania's hydrological situation reversed due to El Nino. Starting in December, reservoirs began filling and would ultimately overflow (and be able to sustain the country through until 2001). Finally, IPTL plant costs came in at US\$150 million (with an additional US\$13 million budgeted for fuel conversion to natural gas for a total of US\$163 million). As a

²⁵⁴ Apart from the arbitration proceedings, discussed below, in which corruption figured prominently, an investigation was also completed to document the corruption, but charges were never brought by the GoT. Certain stakeholders indicated that the failure to bring charges was due to the fact that "too many were implicated," others that "the investigation itself was flawed" and still others that it was "in the best interest of the country not to pursue".

result, Tanzania found itself overcommitted in terms of capacity; the country needed at the most one plant but certainly not two.²⁵⁵

With power now in abundance and financial liabilities mounting, and under pressure from World Bank representatives, TANESCO served a notice of default to IPTL in April 1998 with intentions to terminate the contract. The charge made by the utility was that IPTL substituted medium speed engines for slow speed engines, but did not pass on the capital cost-savings to the utility. Contrary to earlier cost estimates, the government determined that for a similar size/technology plant, it should be paying no more than US\$90 million.²⁵⁶ Disagreement over the substitution²⁵⁷ and the capacity payment persisted throughout 1998, culminating in a Request for Arbitration on behalf of TANESCO at the World Bank's International Centre for Settlement of Investment Disputes (ICSID), headquartered in Washington D.C. Meanwhile, IPTL filed a petition with the High Court of Tanzania claiming that commercial operations were to commence in August 1998, and as a result, IPTL was owed capacity charges of US\$3.6 million for each month since that date. This petition would eventually become part of the ICSID tribunal once it was convened, in June 1999, with both parties agreeing to a cessation of the High Court proceedings.

The tribunal involved several phases. In the first phase, TANESCO attempted to rescind the PPA on the basis of technical issues (namely that medium speed engines were substituted for slow speed engines). In April 2000, in the midst of first phase proceedings, TANESCO additionally requested the Tribunal to hear corruption charges. The request was refused, as no allegations of bribery had been formally pleaded. In May 2000, the tribunal ruled against rescinding the PPA, but stipulated that the capacity payment must be lowered to match actual construction costs. Following on the initial ruling in what may be termed a second phase, TANESCO made additional efforts to rescind the PPA, this time formally raising bribery charges through an Ancillary Claim. Sworn statements were provided by the Permanent Secretary of MEM, Assistant Commissioner for Energy (Petrol & Gas) and Assistant Commissioner for Energy (Electricity). In June, the tribunal ruled that TANESCO could pursue bribery charges, but only within the existing timeframe of the final hearing in one month's time. The tribunal ordered both parties to produce any documents in relation to the charges. The tribunal did not allow wide-ranging interrogations or include a forum to require parties to answer specific questions on bribery allegations.

²⁵⁵ As will be seen, however, the country's demand increased dramatically over the ensuing years and eventually required the capacity of Songas, IPTL and is presently in need of additional capacity.

²⁵⁶ In initial discussions with IPTL sponsors on December 15, 1994, spokespeople for the GoT indicated that they would be willing to pay capacity charges of US\$27.5 kilowatt (kW)/month, which is considerably higher than the US\$90 million investment costs arrived at in 1997.

²⁵⁷ IPTL contends that it briefed TANESCO on the substitution well in advance and that it was made to enhance maintenance of the plant.

By July 2000, TANESCO produced some documents to the Tribunal but requested an extension of three months as it had not yet completed its bribery investigation. The tribunal disallowed any such extension, but proposed to TANESCO to withdraw the bribery charges with the option of raising them later in separate ancillary proceedings after completing its investigation, which the utility never pursued. The Tribunal ultimately ruled: i) allegations of bribery had failed based on information presented, ii) capacity charges should be reduced based on actual and reasonable costs incurred, and iii) there had been no breach in the fuel supply, as alleged by TANESCO. The final award, made in May 2001, upheld the PPA signed in 1995, adjusted the capacity charge to US\$2.6 million per month, and indicated that conversion to natural gas would be as per the original PPA - with the costs of conversion paid by TANESCO (with a benchmark of US\$11.6 million set²⁵⁸) and work to be carried out by Wartsila.

6.4.5 Implications of IPTL dispute on Songas

During the three year dispute between IPTL and TANESCO, Songas would be put on hold out of concern that the utility could not absorb power from two plants and that the ESI was implicated in corrupt dealings. Three critical developments occurred during this period. First, although no additional work was completed by sponsors, the AFUDC continued to compound at a rate of 22 per cent per annum (which will be discussed in detail below). Secondly, the scope of Songas was scaled down from 151 MW (per 1995 negotiations) to 115 MW in light of the expected IPTL capacity.²⁵⁹ Thirdly, significant changes occurred to the composition of the project sponsors. Both the IFC and DEG pulled out of Songas shortly after the IPTL dispute became known (with CDC taking over their associated financial obligations of approximately US\$12 million).²⁶⁰ Furthermore, by 1999, TransCanada arranged for the sale of its majority share to AES, citing a strategic decision to consolidate its assets in North America. Two years later, Ocelot (known at that time as PanOcean, later EastCoast Energy and presently Orca Exploration)²⁶¹ would do the same, however, for different reasons, namely consolidating its

²⁵⁸ Current estimates peg this conversion cost at US\$20 million.

²⁵⁹ The additional capacity in Songas (previously referred to as the Songas expansion) would be demanded with the 2003 drought.

²⁶⁰ IFC's pull-out has also been linked to the small scale of the investment, namely that it was difficult for the organization to go to its board for project approval for an investment of US\$4 million. DEG's pull-out has been linked further to the size of its own organization: the associated dispute with IPTL exposed DEG to too much risk given its small portfolio of projects.

²⁶¹ Ocelot, the initial investor in the Songo Songo gas-to-electricity project, was replaced by its subsidiary company, PanOcean in the Songas project. PanOcean sold its shares in the power project in 2001 to AES to concentrate exclusively in the gas development. In 2004, Pan Ocean spun off its interest in Songo Songo to a separate company: EastCoast Energy, which in April 2007 changed its name to Orca Exploration. PanOcean maintains significant interests in oil fields in Gabon. It should be noted that EastCoast Energy did not bid to develop the Mtwara Gas-to-Electricity Project. Project inception for Mtwara coincided with the time that EastCoast was negotiating its production sharing agreement for Songo Songo; an additional venture was beyond the appetite for the firm, at the time.

interests in the Songo Songo gas field exclusively.²⁶² Thus, by the time the IPTL arbitration had been concluded and sufficient demand had been ascertained, the AFUDC had increased substantially and the original lead Songas' sponsors had all but transformed (with only CDC, TPDC and TDFL maintaining their minority shares in the project).

It was under AES that the PPA was completed and financing for Songas eventually was finalized in October 2001, nearly a decade after Ocelot had first approached the GoT. As with IPTL (for which financing required an informal guarantee by the Malaysian government), the financing for Songas was atypical in terms of global IPP investments. With no available commercial finance, the GoT obtained an IDA credit together with a loan from the EIB which it then on-lent to Songas at a rate of 7.1 per cent.²⁶³ The total debt available to the project, as of October 11, 2001, was equivalent to US\$260 million (US\$200 from IDA and US\$60 million from EIB).^{264 265}

²⁶² In terms of the production sharing agreement between TPDC and Orca Exploration, profits are shared on production with respect to 'additional gas' only. Additional gas is defined as all gas other than that 'protected gas' designated for Ubungo turbines I-V (150 MW) plus the cement factory for the 20 year PPA. For average daily sales of 0-20 million cubic feet per day (MMcfd), TPDC's share of gas revenues is 75 per cent while Orca's is 25 per cent; for 20-30 MMcfd, TPDC 70 per cent, Orca 30 per cent; for 30-40 MMcfd, TPDC 65 per cent, Orca 35 per cent; for 40-50 MMcfd, TPDC 60 per cent, Orca, 40 per cent, for greater than 50 MMcfd, TPDC 45 per cent, Orca, 55 per cent (Orca Exploration 2007:9). Profit sharing for gas in the as of yet unproven section of Songo Songo, will, regardless of average daily sales, be divided on the following terms: TPDC: 45 per cent Orca Exploration: 55 per cent.

²⁶³ Throughout the 1990s, all export credit agencies were off-cover in Tanzania; no foreign commercial banks were willing to lend as there was no clean track record of commercial loan repayment.

²⁶⁴ As per Table 6.2, however, only US\$206 million in DFI funding was ultimately used, only half (US\$108 million) of which came from the IDA credit "Songo Songo Gas Development and Power Generation Project" (World Bank Credit 3569-TA). The remaining debt was sourced from EIB, old loans and previous credits.

²⁶⁵ The reason why concessionary loans were not passed on in entirety to Songas and subsequently to TANESCO to reduce costs further was that the Songo Songo gas-to-electricity project was part of a plan to gradually commercialize TANESCO. Thus, while loan rates were increased from 0.75 per cent to 7.1 per cent, they were still significantly below commercial bank loan rates in the mid-teens.

Table 6.4: Songas project financing, security arrangements and credit enhancements²⁶⁶

Project	Estimated project costs (million US\$)	Equity	Debt	Security arrangements and credit enhancements included in the PPA		
				Liquidity facility ²⁶⁷	Escrow account	Other
Songas (115 MW)	US\$320	(25%) Return on equity 22%	(75%) Interest rate 7.1%	Equivalent to 4 months capacity charge	GoT to match every \$ spent by project company	AFUDC
Songas Project expansion (65 MW)	\$50	100%		Equivalent to 4 months capacity charge	No new escrow (existing escrow used in part to buy down AFUDC)	None

With approximately four years as lead equity shareholder and with work well underway on the refurbishment of the Songas turbines, AES began to negotiate the sale of its shares. AES's exit from the project was a product of the global downturn in the private power sector and foreign direct investment in general, caused by the Asian and subsequent Latin American financial crisis, after-shocks of 9/11 and the Enron scandal—to which AES was closely associated by analysts by the mere fact that it was an American power company. AES also lost significant amounts of money on its investments in imploding markets in South America. With a plummeting stock price, AES was pressured to sell assets, among them Songas, by both bankers and shareholders.

Globelec, which as previously noted, was spun off of CDC in 2002 (as the holder of CDC's portfolio of power sector assets), picked up the majority of AES's shares to represent the new lead shareholder in Songas, with the balance going to FMO.²⁶⁸ Thus by April 2003, still one year before COD, the project had seen three different lead shareholders. It was during this sale that the GoT negotiated to buy down the AFUDC, which, according to certain stakeholders, AES had resisted. Initially, as previously indicated, the AFUDC was to be wrapped into the capacity charge, however, by April 2003 the amount had ballooned to US\$103 million and would have meant a monthly capacity charge of more than US\$6 million, equivalent to almost 30 per cent of TANESCO's revenues. The buy-down was financed by:

²⁶⁶ Table 6.4 contrasts with Table 6.2 as it depicts estimated project costs, and the previous table highlighted actual project costs. The Songas project came in under budget, although if we consider the AFUDC, as discussed in detail later, total costs were actually greater not less.

²⁶⁷ Like the declining escrow account for Songas mentioned earlier, the liquidity facility is fully funded to four times non-subordinated financial obligations (equivalent to 4 x US\$2.7 million) for the first three years of operations and reduced to 2 x US\$2.7 million throughout 20 years of operations, being cover against TANESCO non-payments or partial payments.

²⁶⁸ After the AES sale, equity shares and associated financial commitments (expressed in US\$ million) in Songas were as follows: Globelec: US\$33.8 (56%); FMO: US\$14.6 (24%); TDFL: US\$4 (7%); CDC: US\$3.6 (6%); TPDC: US\$3 (5%) and TANESCO: US\$1 (2%). This does not reflect the additional US\$50 million that Globelec committed for the expansion, which as noted in footnote 231, TANESCO is presently trying to refinance, however, as of May 2007 no progress has been recorded.

the Songas Escrow facility (40 per cent) which by 2003 totalled about US\$50 million, Ministry of Finance (50 per cent) and TANESCO (10 per cent). Globeleq did not require an escrow facility as a condition of its purchase, and the facility has not been replenished post AFUDC buy-down.

With financial closure completed, the AFUDC out of the way and a new shareholder at the helm, Songas was nearly set for operation. The only piece left was the plant expansion of 65 MW, which although foreseen in the original PPA, was postponed until 2005 due to lack of demand. The expansion was 100 per cent financed by Globeleq (although presently efforts are being made to refinance). The following section addresses operations and associated costs of each plant.

6.5 Analysis of IPP operations and costs

Although Tanzania's IPPs were considerably delayed, since coming on line starting in 2002, the plants have brought about a transformation of the country's ESI—from nearly 80 per cent hydro dependent to thermal plants making up more than 50 per cent of generation during 2005 and 2006. By 2007, with the return of normal hydrological conditions, reliance on IPPs dropped to 20 per cent of total generation. Songas has been running at about 50 per cent capacity, with limited amounts presently contributed by the emergency plants (Aggreko, Alstom, Richmond/Dowans) as well as about 4MW from AG&P. IPTL is, according to stakeholders, virtually shut down due to the difference in fuel costs. With the two of the three emergency plants running on Songo Songo gas at US\$2.17/MMBtu and with IPTL's conversion to natural gas outstanding and therefore running still on HFO at US\$8/MMBtu, there is little argument about who to dispatch first. It should, however, be noted, as mentioned at the outset, that this and subsequent analyses focus primarily on the period up to 2007 and therefore almost exclusively on IPTL and Songas.

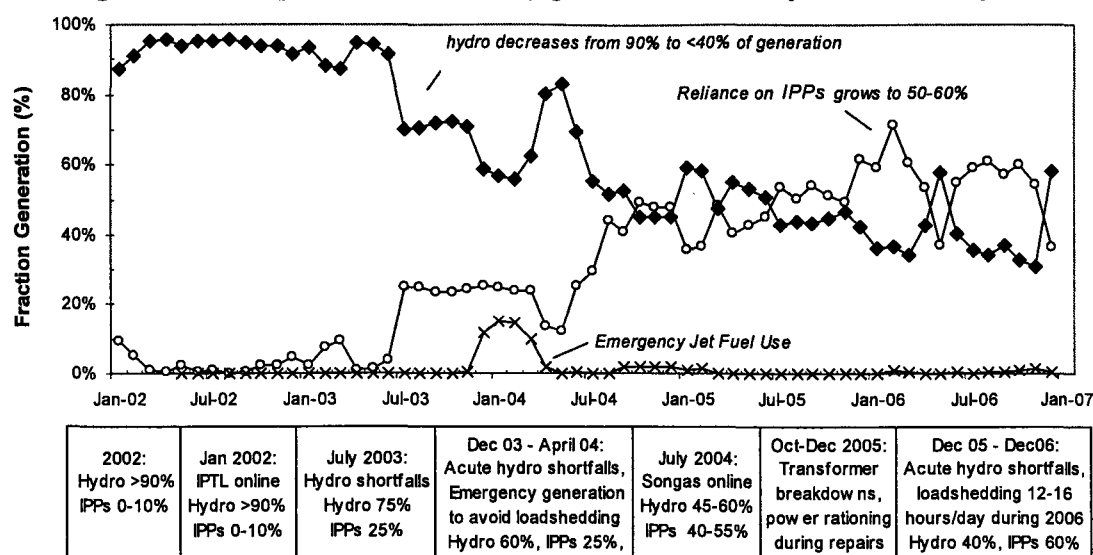
6.5.1 Generation and capacity utilization

During a period of drought, starting in 2003, the country turned extensively to power from IPTL. Subsequently, Songas was integrated into the ESI, albeit later than initially expected, for drought-relief. As noted in the introduction, the thermal power from IPPs helped the country to avoid serious load shedding between 2002 and the end of 2005,²⁶⁹ which has saved it around US\$1.00/kWh of outage averted (or about 5-10 times the cost of generating electricity) (ESMAP, 1998).²⁷⁰

²⁶⁹ See footnote 225 for a discussion of load shedding due to generation constraints commencing in 2006.

²⁷⁰ A study by ESMAP (ESMAP 1998) estimates US\$1.00 per kilowatt hour as the cost of outages in Tanzania, which is derived from earlier studies showing: the cost of unannounced outages to industrial customers at US\$ 2.25/kWh (Tanzanian Industrial Research Development Organization, TIRDO study), the cost of outages to other customers at US\$ 0.30-\$1.00/kWh (Acres International and USAID 1992

Figure 6.2: Composition of electricity generation, January 2002- January 2007



Source: Ghanadan and Eberhard (2007:32)

With increasing pressures due to drought combined with growing demand, the IPP plants were run at near capacity, between 2003 and 2006, contrary to initial concerns about the country's ability to absorb the power.

Several points are noteworthy in this context. Firstly, delivery of Songo Songo gas was delayed, which, due to an acute power shortage necessitated emergency generation, namely running existing Ubungo turbines on imported jet fuel as well as additional usage of IPTL. Secondly, Songas was not at full availability its first year of operation, which also necessitated additional use of IPTL.²⁷¹

Explanations for Songas' delays and subsequent shortfall in capacity have been attributed to failure of a sub-contractor working on the gas infrastructure to deliver on time, expansion work and technical failure of existing turbines. The plant was offline in January 2005 to make connection for the expansion project. Availability suffered again in May-June 2005 due to failure of turbine III. Although Songas was required to pay penalties for these missteps, according to sources within TANESCO and Songas, penalties do not match the additional costs

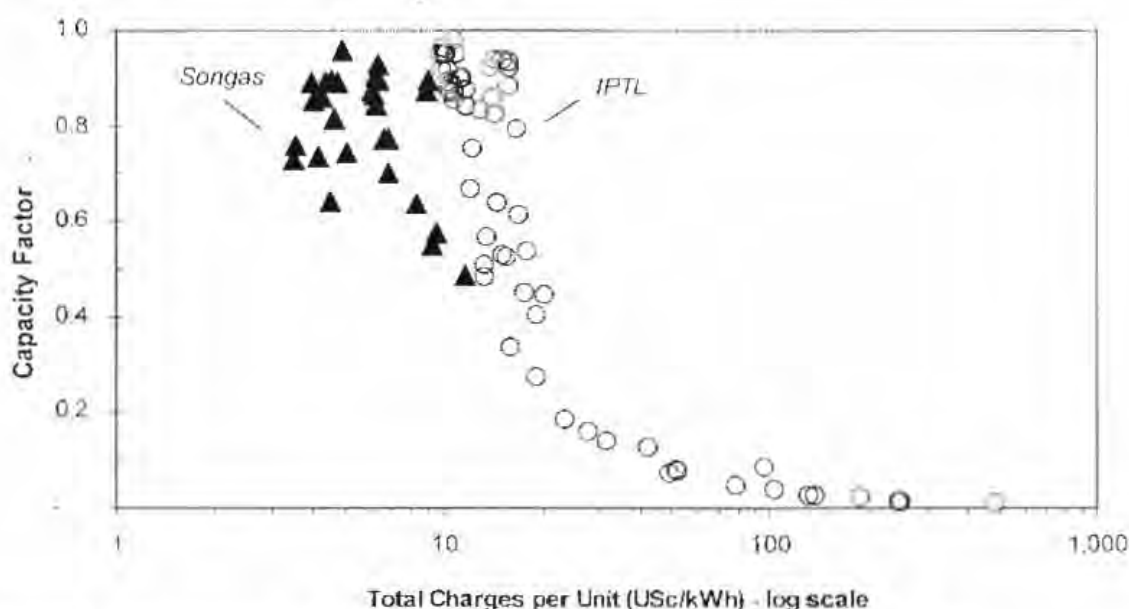
study), and the cost of diesel back-up generation at \$0.12-0.33/kWh (ESMAP estimate). It can be noted that the latter estimate has increased considerably over the past few years due to the strong increase in international crude oil and refined products prices.

²⁷¹ IPP monthly average capacity factors are calculated from name plate capacity and monthly electricity generation, based on 100 MW capacity for IPTL and incremental increases in capacity with development of Songas: 78 MW (Aug-Sept, 2005), 115 MW (Oct 1, 2004-March 9, 2005), 151 MW (March 10, 2005-June 7, 2005), and 190 MW (beginning June 8, 2005). In the case of Songas 190 MW represents the base maximum capacity, according to sponsors, with the base dependable capacity at 178 MW (Songas per com 2007). In all other instances, throughout this thesis, 180 MW is used as the capacity figure for Songas.

incurred by the utility during the period, which amounted to US\$43 million and was financed through an emergency World Bank loan.²⁷²

Figure 6.3 highlights the extent to which the capacity factor alters the per kilowatt hour charge of each of the plants. For instance at a capacity factor of 1 per cent, at which IPTL was run initially, the country saw charges of US\$4.80/kWh. Approaching nearly 100 per cent capacity use, IPTL charges fall to US\$0.097 per kWh. At full capacity, however, IPTL charges are still nearly double those of Songas, despite the fact that the Songas capacity charge is comprehensive of the gas infrastructure.

Figure 6.3: IPP Total Charges per Unit at Different Levels of Plant Use, Based on Monthly Data, Jan 2002 – Dec 2006²⁷³



Source: based on Gratwick, Ghanadan and Eberhard (2006:45) and generated by Ghanadan

6.5.2 Fuel bills, deals and conversion

While the capacity factor goes a long way in explaining the different prices at the end of the spectrum, especially for IPTL, there is a critical difference in per kWh charges (and total monthly charges) that is explained by the difference in fuel on which IPTL and Songas are operating. Songas uses domestic natural gas, whereas IPTL relies on imported diesel fuel.

²⁷² Further outages in 2006 were caused by what has been described as technical fatigue due to the fact that the open cycle plant was base-loaded for such an extended period. Songas paid for repairs, and TANESCO did not bear any direct cost other than of course lost revenue due to the fact that the utility had no reserve margin. As a result of the outage, during 2006, Songas' availability dropped to 89.4 per cent, slightly lower than the target of 91.3 per cent, specified in the PPA. The plant, as of 2007, has, however, maintained an average of 91.8 per cent.

²⁷³ Total charges per unit include energy and capacity charges normalized to generation, and represent monthly averages. IPTL data points include Jan 2002–December 2006 ($n=58$ months); Songas data points include July 2004–December 2006 ($n=28$ months). Unit charges are VAT exclusive.

The gas price for Songas for turbines I-V and for the Twiga cement plant, which was developed as part of the Songo Songo gas-to-electricity project, is set at US\$0.55/ MMBtu, indexed to the USA CPI over the course of the 20 year PPA. The special price of US\$0.55 only pertains to the 'protected gas' that has been earmarked for Ubungo turbines I-V and the cement factory.²⁷⁴ All additional gas that is sold from Songo Songo is priced at a maximum of 75 per cent the buyer's liquid fuel equivalent. Presently TANESCO is negotiating long-term gas contracts at between approximately US\$2.00 and US\$2.40 per Gigajoule GJ (1 GJ = .95 MMBtu).²⁷⁵

Table 6.5: Songo Songo gas reserves pricing and usage

Characterization	Price	Notes
I. Protected Gas	US\$0.55/MMBtu	Allocated for Songas (turbines I-V = 150 MW) plus cement factory for 20 year PPA
II. Additional Gas	Maximum 75% of liquid fuel equivalent	All non-protected gas, includes both reserve gas described below and gas currently used for Ubungo VI (below), IPTL fuel would come from 'additional gas'
i) Reserve Gas	Maximum 75% of liquid fuel equivalent	100 Bcf of gas set aside for government to determine use within 5 years of transfer date (July 2004)

Note: Bcf: billion cubic feet

Although gas sales with third parties are developing (from seven companies in 2006 to 16 as of 2007), until recently they were a fraction of total production; Songas and therefore TANESCO (since fuel is a pass-through) was the primary taker, and therefore in essence the market maker. Songas' fuel price was conceived of as part of the initial project concept to offset the capacity charges so that the utility would not shoulder the full weight of developing the country's gas infrastructure.

While not benefiting from special 'protected gas', IPTL was, from project inception, slated to be converted to run on natural gas and source its fuel from the 'additional gas' reserves of Songo Songo. The project was therefore to benefit from an estimated minimum fuel cost savings of 25 per cent (given the additional gas price set at a maximum of 75 per cent the liquid fuel equivalent). This plan was reconfirmed in the IPTL arbitration when US\$11.6 million was tagged as an estimate to be paid by TANESCO for converting IPTL.²⁷⁶ Although

²⁷⁴ The reason why Ubungo turbine VI was not included in the original gas deal is due to the fact that it was not part of the original project concept. Gas is presently (as of May 2007) being sold at US\$2.17 MMBtu High Heat Value (HHV), the same price for which gas is being sold to Aggreko and Richmond/Dowans.

²⁷⁵ Benchmarking these prices represents a particular challenge since there were few options for the gas as it was virtually a stranded asset. A comparison with the Henry Hub natural gas spot prices of US\$14.80/MMBtu (December 2005) provides little actual value. A potentially more accurate comparison may be the net-back value of exporting gas to Kenya (Mombassa), which has been approximated at more than US\$3.00/MMBtu.

²⁷⁶ As noted in footnote 258 current cost estimates for conversion are closer to US\$20 million.

the savings is not equivalent to Songas, it would amount to a reduction of approximately US\$1 million per month (given a current average monthly fuel charge of about US\$3.6 million).²⁷⁷

Songo Songo gas was available starting July 2004. However, IPTL has still not been converted. Conversion has repeatedly been delayed. In 2005, stakeholders attributed conversion delays to a host of factors: probability and availability of fuel reserves; technological conversion challenges; securing financing; resistance from lenders; fuel pricing formula; and debt and equity renegotiation/disputes. Of these six factors contributing to delays, among the most common cited by stakeholders was that concerning conversion of the technology itself. The engines needed to be converted, but Wartsila SWD 18 V 38 diesel engines had never run on natural gas. Thus Wartsila, which is also the operator of IPTL, first needed to conduct a series of tests. Although according to one stakeholder close to the project, "this is not rocket science", a test-bench must be booked and time allotted to carry out the work. As of 2007, conversion delays are primarily attributed to agreement not yet being reached between owners and debt-holders (which will be discussed in detail in section 6.5.3). Furthermore, new potential challenges have arisen with regard to the Songo Songo gas processing plant.

The capacity of the gas processing plant is about 105 million standard cubic feet per day (MMcfd), and as of May 2007, the plant was utilized at 65 per cent, with Songas, Aggreko, Alstom and the 14 other gas customers. With the IPTL conversion (100MW), capacity utilization will be 100 per cent with a buffer of approximately 20mmscfd. Thus, when/if rainfall subsidies, there will be insufficient capacity to feed the 100 MW Wartsila plant at Ubungu (expected in September 2007) and the Tegeta plant (expected in July 2008). Although the procurement process has started to increase capacity, here also delays have been encountered, which could impede gas delivery. Thus, presently under discussion is a plan to further delay the IPTL conversion to ensure that Wartsila is supplied. Conversion might therefore happen as late as 2009.

6.5.3 Monthly charges to TANESCO

Actual monthly charges to TANESCO for operating the two IPPs (inclusive of both energy and capacity payments) during 2005 amounted to an average of US\$13 million per month, or well over 50 per cent of TANESCO's monthly revenue. For 2006, this figure skyrocketed to a staggering 96 per cent of TANESCO's monthly revenues due to exchange rate fluctuations, increases in the price of HFO and the reduction in TANESCO's revenues. Although capacity factors matter in terms of the price per kilowatt hour, they have no bearing on the total capacity charge, which is a fixed monthly charge to the utility to finance the capital

²⁷⁷ Stakeholders in the MEM indicate that fuel savings will be even greater for IPTL, at 60 per cent (not 75 per cent) of present costs, based on HFO prices. In addition, further reductions in cost may result from the increase in the efficiency of the plant running on natural gas.

cost of the project, unlike the energy charge, which varies with operation. For IPTL, these capacity charges were negotiated on a straight-line basis for the 20 year duration of the PPA, which means provided there are no changes to the project ownership or debt, the utility will pay US\$2.6 million monthly, adjusted for inflation, going forward. For Songas, the situation is different, as the capacity charge declines on a straight-line basis to zero over the life of the project, with the loan repaid by year 18.

Table 6.6: IPP monthly charges and generation²⁷⁸

IPTL	2005	2006	Whole Period	Whole Period
	Average	Average	Average	Range
Capacity Charge	2.6	2.7	2.5	2.3 – 2.8
Energy Charge	3.5	4.7	3.0	0.03 – 6.4
VAT (20%)	1.5	1.8	1.4	0.05 – 2.3
Total IPTL Charges (million US\$/mo)	\$7.6	9.3	\$6.9	\$2.9 – 11.4
Total IPTL Generation (GWh/mo)	48.1	53.4	41.6	0.5 - 73
Songas	2005	2006	Whole Period	Whole Period
	Average	Average	Average	Range
Capacity Charge	3.3	5.6	4.3	2.2 – 6.2
Energy Charge	1.2	1.3	1.6	0.2 – 2.0
VAT (20%)	0.8	1.4	1.1	1.0 – 1.6
Total Songas Charges (million US\$/mo)	\$5.4	8.2	\$6.6	\$3.9 – 9.6
Total Songas Generation (GWh/mo)	95.8	111	97.1	19 – 130
IPP Charges (million US\$/mo)	\$13.0	\$17.5	10.0	\$2.3-20.8
TANESCO Revenue (million US\$/mo)	\$19.1	\$18.3	\$16.6	\$12.2 - 22.0
IPP Charges vs. TANESCO Revenue (%)	68%	96%	62%	16-107%
IPP Generation (GWh/mo)	144	165	91	0.54 – 193
Total Generation (GWh/mo)	278	298	278	233 – 325
IPP vs. Total Generation (%)	31%	55%	31%	0.2-71%

Source: based on Gratwick, Ghanadan and Eberhard (2006:48), generated and revised by Ghanadan

Note: GWh: gigawatt hours; mo: month

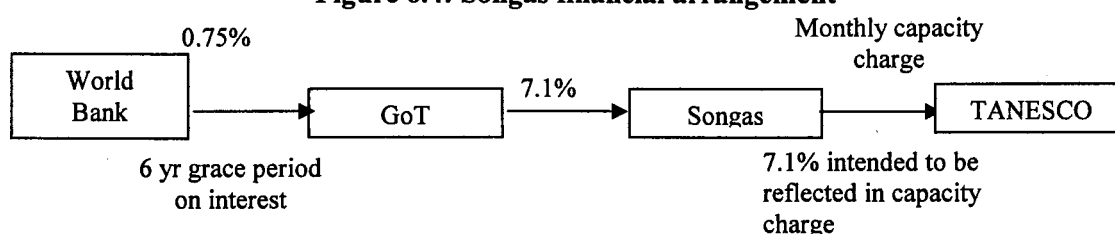
A number of issues are worth reiterating in this context. First, the fluctuations in the capacity charge depicted in Table 6.6 relate to: annual inflation adjustments for both IPTL and Songas; change in Songas debt payments (discussed below); increased Songas capacity, with turbines V and VI coming online mid-February and end-May 2005, respectively. Second, Songas' capacity charges are inclusive of the entire gas infrastructure and should not be mistaken for the price of electricity generated from Ubungo alone. Third, as also discussed

²⁷⁸ Average IPP monthly charges for 2005 are based on monthly data available for the period Jan to Sept 2005. Average values for the whole period for each respective IPP include: IPTL Jan 02-Dec 06, for Songas July 04- Dec 06. Also note that total IPP charges and total IPP generation during whole period do not equal the sum of individual IPTL and Songas values. Total charges span the whole period from 2002 to Dec 2006. However, Songas only came on line in July 2004. Thus for many months only IPTL was running, and average values and ranges do not correspond.

above, the most significant monthly charge for 2005 has been the variable energy charge for IPTL, a cost, which is expected to reduce by a minimum of 25 per cent after the plant is converted to run on natural gas.

A final issue relevant to the present capacity charges is that TANESCO has not been paying the subordinated debt portion of the Songas capacity charge since May 2005, and the liquidity facility is presently at zero.²⁷⁹ Full charges would reflect the 7.1 per cent interest rate and amount to approximately US\$5.8 million per month (plus US\$1 million VAT), with US\$4.2 million for turbines I through IV and an additional US\$1.6 million for turbines V and VI.

Figure 6.4: Songas financial arrangement



Source: author's compilation based on stakeholder input

The current non-payment of the subordinated debt was provided for in the subsidiary Loan Agreement dated October 11, 2001. Due to the fact that GoT borrowed funds from IDA and on-lent to Songas (at a premium), if TANESCO fails to pay Songas the amount equivalent to the principle and interest, Songas is relieved and forgiven up to that amount, while TANESCO is treated as a borrower at more stringent interest but relieved until it is able to pay. Since TANESCO is wholly owned by the state, it is up to TANESCO to make a case either to pay or swap with other obligations of the State. Initially it was expected that the existing arrangement would continue until such time when the government declares the utility bankrupt or TANESCO becomes liquid and pays, however, presently, there is a strong likelihood that the debt may be forgiven by the GoT as part of TANESCO's Revenue Recovery Plan. Regardless of the final resolution, this arrangement has helped the utility to reduce its present financial liabilities for Songas to almost half.

Although there has yet to be impact on either plant operations or charges, equally noteworthy in this context are the idiosyncrasies and conflicts related to IPTL's debt structure, which have evolved after COD. In February 2002, only one month after IPTL commenced commercial operations, local partner VIP petitioned the High Court of Tanzania to wind up the project company. Reasons provided by VIP were: oppression by the majority shareholder (namely that Mechmar refused to involve the VIP nominee director of IPTL in corporate

²⁷⁹ The utility is still paying the EIB portion of its subordinated debt, i.e. it only applies to the World Bank portion of the debt.

decisions); fraud by Mechmar in inflating the IPTL capital cost; and failure by Mechmar to pay its equity contribution (i.e. the project was 100 per cent debt financed). IPTL management has denied all claims.²⁸⁰ There has been no resolution of this conflict.

In the meantime, however, IPTL's debt, which was non-performing, was first purchased by Danaharta, a Malaysian entity that bought up many non-performing loans after the East Asian financial crisis, and then resold to Standard Chartered for US\$74 million in November 2005. VIP has subsequently contested the sale to Standard Chartered on the basis that the very loans that were resold are under dispute. Meanwhile, since the sale to Standard Chartered, the GoT has been in negotiations to buy IPTL's debt, with the Ministry of Energy indicating that such a purchase should be finalized by end-2007.²⁸¹ Furthermore, it is expected that subsequent to the debt purchase, the government will also buy out the firm's equity. Should any sale be finalized with GoT, the project may see a significant reduction (if not complete elimination) in capacity charges (see Appendix A for a breakdown of project costs). Finally, an important point to reiterate is that conversion is expected after the gas processing plant increases capacity and the debt and equity buy-out is finalized. There is a remote chance that if conversion is delayed, with new TANESCO thermal due online (namely the 100 MW Wartsila plant at Ubungu), IPTL may actually be mothballed until such time that it may run on natural gas.

6.5.4 Benchmarking costs

It has been established that IPTL is presently more expensive than Songas, but are the costs reasonable? Based on construction costs per kilowatt, at both its pre-arbitration costs of US\$1,635 and its post-arbitration costs of US\$1,272, IPTL appears to have the highest such costs within a sample of similar size/technology IPPs in developing countries. Kenya's Ibrafrica plant is, however, in close proximity, indicating that costs may be generally inflated for the East Africa region. Although Songas employs a different technology, namely OCGT,²⁸² it is worth noting that isolating project costs related only to the plant (as detailed in footnote 231), the per kilowatt construction costs are approximately US\$684 or about half those of IPTL.

Given Songas' lower variable cost, the plant has been dispatched before IPTL (following basic merit order dispatch protocol). Thus, Songas is contributing more in terms of total generation. A notable point in this context is that although IPTL constituted only 37 per cent of

²⁸⁰ With regard to the equity contribution, IPTL maintains that equity has been contributed by Mechmar; the firm's financial situation has changed drastically, however, since the arbitration, during which period, IPTL incurred significant debt.

²⁸¹ The sale price to GoT has been estimated at between US\$70 and 80 million, although VIP asserts that, according to the amortization schedule in the arbitration award, the value of the debt should be no more than US\$40 million.

²⁸² Using natural gas as a fuel makes Songas also more efficient from a fuel usage perspective.

the total IPP generation for 2005, when both plants were running at full capacity, its costs accounted for 62 per cent of the total (IPP generation).

An analysis of the kilowatt charge per hour of the two projects confirms the contrast in costs. Although IPTL has been running at a slightly higher capacity factor (70 per cent in 2005)—the total kWh charge for the plant was still more than two and a half times that of Songas.

In sum, IPTL costs do appear to be higher both than the international norm and than its IPP counterpart, Songas. There are, however, several costs to Songas that are not presently reflected in the capacity charge, namely the AFUDC, the full cost of debt, the escrow facility²⁸³, and the sunk cost of the original drilling of the wells in the 1970s. An assessment of Songas' total charge per unit including these elements would be measurably higher.

6.6 Balancing outcomes?

The development outcome for Tanzania has been mixed. The country has been able to expand its generation capacity and did not resort to serious load shedding between 2002 and 2005 (see footnote 225). Tanzania also has succeeded in commercializing its natural gas, which has helped reduce the fuel bill for the state utility and numerous other small industries (previously reliant on petroleum imports) as well as alleviate the pressures related to securing quality fuel in a timely manner from abroad. GoT may claim a payback period of less than half the time originally estimated on turbines I-IV of the Songas project (or three years instead of six), due to the increase in JET A-1 fuel prices.²⁸⁴ Songo Songo gas has also been critical in fuelling emergency plants, Aggreko and Richmond/Dowans.

Despite these developmental gains, power in the case of IPTL is, as has been shown in the previous section, proving to be more expensive than the international norm (even post-arbitration). Furthermore, the IPTL arbitration was particularly costly to Tanzania, both in terms of direct and indirect costs of arbitration, and eroding credibility of the project in the eyes of many stakeholders. Songas, while less costly than IPTL, did incur significant costs to the country in the form of the AFUDC and the escrow account. The extent to which IPTL and/or

²⁸³ Additional costs related to Songas: 1) the AFUDC was paid down by GoT, Treasury and TANESCO for US\$103 to reduce the capacity charge; 2) the subordinated portion of Songas World Bank debt is currently not being paid; 3) the escrow facility of US\$50 million (which was used to help pay down the AFUDC is presently only US\$2.5 million) but did until 2003 tie up GoT funds; 4) the cost of the original drilling of the wells, which amounted to approximately US\$100 million, is as indicated above, treated as a 'sunk cost'.

²⁸⁴ This is calculated by taking: the total project cost (debt US\$206 million + equity US\$60 million), divided by the product of 12 months and monthly energy saving (replacing Jet A-1 fuel with natural gas) of about US\$3.5 million for UGT1 -UGT4, by the then prices, which means that the payback period is almost 6.33 years. Since Jet A-1 fuel prices doubled in 2005, the payback period is reduced by half to almost three years.

IPTL-related events inflated Songas costs (particularly the AFUDC being 75 per cent more expensive than expected) should not be overlooked.

With regard to the investment outcome, it too has been mixed. Parties have secured a ROE of 22 per cent, but there has been significant equity turnover, and Globeleq is the third lead shareholder on the Songas project, after previous ones lost interest due in part to project delays. The present majority shareholder in IPTL, Mechmar, has been trying to sell the asset for several years, and the minority shareholder issued a winding up petition to terminate the company four years ago (which remains pending). TANESCO has been unable to make its full debt payments (to Songas and hence to the GoT), and IPTL's loans were declared non-performing, and then bought by Danaharta, an initiative of the Government of Malaysia, and most recently by Standard Chartered. New IPP capacity, namely ATJL, has been added, without a formal framework. Meanwhile, the emergency power that plugged the 2006 power deficit was financed through state and concessionary funds, as are the new plants expected at Ubungu and Tegeta.

With considerable negative results reported, and outcomes ultimately recorded as mixed, is it appropriate to discuss balance and sustainability? It would appear that such results do not translate into sustainability for IPTL. A resolution may be on the horizon if the government buys the IPTL debt, but such would not represent sustainability with regard to the original project concept and partners. In terms of Songas, although results have been superior to IPTL, according to the firm, as of June 2007, "the investment has the poorest payment and security record of any of our plants in Africa and Asia." Although the firm is presently selling all of its other assets, as previously discussed, it is retaining those in Sub-Saharan Africa due to the fact that the indicative bids have not been favourable. Does this in turn mean that outcomes are rated poorly? This thesis would argue that the Songas contract may ultimately be upheld, but it is unlikely that a similar experience will be actively sought again. It may be sustainable for one project, but surely not replicable.

The following sections examine the myriad factors that affected outcomes. Of the different exogenous stresses reviewed to date (civil strife, macroeconomic shock and associated currency devaluation and drought), only one is taken up in the discussion below, and only in the broader context of electricity sector reforms. As seen in Kenya, there has been no evidence for macroeconomic shock; instead, in evidence is creeping devaluation throughout the course of the 1990s, in Tanzania, followed by a relatively stable currency environment in the period since the IPPs have come online. Thus there has been little to no perceived impact to date, however, with PPAs of 20 year duration, denominated in US dollars, there is always a risk of future impact, which may be exacerbated by the rising price of fuel imports (so long as IPTL relies on HFO).

6.6.1 The investment climate: risk perceptions

The first initiative to develop the Songo Songo gas field collapsed in the 1980s largely due to the poor investment climate. At the time of the inception of the IPP plans in the early-mid 1990s, little had improved in terms of the investment conditions. It is arguable that conditions had even worsened, with an all time high inflation level of between 30-35 per cent reported in the mid-1990s and no foreign commercial lenders willing to lend to the sector.

While there were several impediments to the initial bid for Songas (size of plant and short bid time), the investment climate features prominently in why more investors did not come to the table. With the risk of expropriation still perceived, investors took little interest in the Songas bid, with only two of the 16 firms invited submitting bids.²⁸⁵ It should also be noted that the mere fact that there were no previous such investments exacerbated the perception of risk.

Both IPTL and Songas eventually obtained debt at interest rates of less than 10 per cent (below commercial rates, available in the mid-teens), but the debt was not easy to come by, which may also be linked to the poorly perceived investment climate in Tanzania. In the case of IPTL, eventually the Government of Malaysia intervened to convince two Malaysian banks that their loans would be secure, which amounted to an informal guarantee on the part of the Malaysian government.

In the case of the Songo Songo gas-to-electricity project, in a departure from most project-financed IPP deals globally, the GoT obtained concessionary loans, which it then on-lent to the project sponsor. Although less costly than commercial debt (which again was not available to the sector at the time), these loans required substantial time and conditions (with the World Bank mandating that any future power investments in excess of US\$5 million first receive World Bank approval--a more stringent condition than that laid out in the Power VI plan, which only required notification not approval, see footnote 246).

Although both IPTL and Songas were able to obtain debt at interest rates of less than 10 per cent, the two project companies required a ROE of 22 per cent, a further indication of the riskiness of the investments and the general climate. According to sponsors, this was comparable to the ROE of projects with similar risk profiles within the region and adequately reflected the risk inherent in the Tanzanian ESI, namely that TANESCO, the off-taker, had no experience in paying IPP capacity charges and was financially feeble at the time.

It is arguable, however, that much of the risk was mitigated by additional facilities negotiated by the projects, which have been used extensively for infrastructure projects globally. Both projects negotiated liquidity-type facilities, (although IPTL's is referred to as an escrow account and has yet to materialize). In addition, IPTL obtained a sovereign guarantee

²⁸⁵ Insofar as there was no organized competitive bid for IPTL, it is difficult to evaluate the direct impact of the investment climate on the bid.

equivalent to the value of the PPA. Songas received no outright guarantee, but it did convince the GoT to establish an escrow facility and provide a rate of 22 per cent on AFUDC compounding annually.

Public stakeholders contend that fear of the obsolescing bargain, in such an investment climate, did motivate these extra protections. This has, however, been countered by private stakeholders who insist on both the standard nature of such additional protections as well as the now accepted position of the private sector playing a critical role in providing infrastructure, i.e. no longer accepted practice that assets should default to state hands. What does the evidence say? Have bargains obsolesced? Have security measures, as seen in Kenya, reduced and/or eliminated the obsolescence? For Tanzania at the end of a decade of private power, one of the IPPs may be returning in part to state control and the next long-term power is being provided by the state, with concessionary funding. These developments do not, however, represent any outright or creeping expropriation. Instead, they seem to point to an attempt at redressing the perceived imbalance in development and investment outcomes. Thus, the obsolescing bargain may have played a role in motivating behaviours, but associated protections that follow from the obsolescing bargain have, in contrast, to Kenya, not been determinative. Instead, it is the apparent imbalance that has been instrumental in bringing about changes to the present and future deals.

This is still not the whole story. More remains to be said about how such an imbalance came about. Although the investment climate contributed significantly to outcomes, one cannot attribute to it all the project ills or benefits. There was after all no independent regulator to review PPA contracts. Furthermore, other factors such as actual project plans and execution have contributed significantly to outcomes.

6.6.2 The electricity sector: drought, doubt and reform

The management of the electricity sector, which was widely affected by drought and the intervention of other ministries, played an equally if not more important role in determining project outcomes than those previously discussed. The primary issue of relevance in this context is the planning and execution of the Power System Master Plan, which initially included specifications for Songas, but not for IPTL.

Throughout the early and mid-1990s, Tanzania experienced severe drought conditions and power shortages. It was in this emergency context that four turbines were installed at Ubungu prior to completion of the Songas deal. It was also in this context that IPTL first bid to build fast track power in Tanzania. According to several stakeholders in the MEM, they were roughly operating within the Master Plan but on a six month timeframe with the intent of solving the drought induced shortages as expeditiously as possible. But six months came and

went with Songas, and sponsors and other key stakeholders did not see the project materializing.

With deadlines passing and power cuts persisting, it is alleged that other ministries, affected by the power cuts, started second guessing the six month fix. There was a general sense that TANESCO and MEM, following the World Bank procurement procedures and relying on concessionary loans, were not able to deliver projects on time to address the shortages. As noted previously, the cost of unserved electricity to the economy was high and therefore Tanzania paid dearly for no power. Thus, the backdrop of the IPTL agreement appears to have been a failure to deliver on the Master Plan and hefty associated costs for many Tanzanians facing loss of services, TANESCO facing loss in revenue, and the Tanzanian economy facing loss of productivity, together with a clear interest in collaborating with Malaysian investors in the context of South-South partnerships. Ultimately, the sector suffered from poor planning and execution, which interfered with the one plant solution and the original Master Plan.

It is difficult to fully assess the impacts of the overall ESI reform process on the IPPs. The IPP deals were concluded, despite the postponement of the unbundling of TANESCO, its privatisation, and the establishment of the regulatory agency. Thus, the sequencing of the reforms did not follow the standard prescription outlined in Chapter two. Although such a sequence, to take just one example, may ultimately enhance the transparency of procurement processes by having the regulator precede IPP bids, it was not followed in Tanzania due to the realities of the day: immediate generation required amidst drought conditions.²⁸⁶ The private management contract for TANESCO initially improved its financial position, and the utility was in a better position to service its PPAs – however, persistent drought conditions changed. Initially, the GoT stepped in to assist TANESCO with approximately 30 per cent of the charges, however, as of mid-2007, GoT shouldered 100 per cent of the charges, which is expected to continue until such time that TANESCO recovers (via its Revenue Recovery Plan). In reflecting on reforms, stakeholders provide a range of comments. Some assert that full implementation of reforms would have radically changed that status quo. The country could have had cheaper power, including possibly sourced from the Southern African Power Pool, and may not have faced the same level of emergency situation as it did through 2006. Others argue that reforms may not have altered the present condition of the ESI. The drought and political interference could have easily sabotaged any Master Plan and attempts to screen projects by an independent regulator.

Stakeholders insist further tariff increases are necessary to deal with the increasing costs of generation with reliance on more costly IPPs. However, these increases have a high cost to

²⁸⁶ The extent to which such divergence from the model calls into question the validity of the model will be probed in section 7.7.

the economy and society, as Tanzania is trying to make industrial tariffs competitive with neighbouring countries and residential customers have already experienced a tripling of residential bills in the last three years. The need for further tariff increases - effectively a result of IPTL's high construction charges, Songas' high interest charges, delays in conversion of IPTL, and ostensibly high private sector returns - flies in the face of promises to the public that tariffs would decrease rather than increase with reforms. Notably, electrification rates have not increased, as revenue gains are going to pay for more costly generation rather than investments in expanding services. The IPPs filled a critical gap in supplying much needed power. However, combined IPP charges have left little for other improvements, despite the utility's doubling of revenues.

6.6.3 Making and breaking the Songas project

Although both the investment climate and the state and management of the electricity sector go a long way in explaining development and investment outcomes, a series of project-specific factors provide even further clarity as to how and why projects have fared for the host country and investors. In terms of Songas, five main issues stand out: the characteristics and the conditions of the project partners, the idiosyncrasy of the project financing, the PPA's AFUDC, the benefits of the gas agreement and the equity turnover.

World Bank put Songas on hold in 1997 after it became clear that IPTL was coming online. The World Bank only gave the go ahead for the Songas project to recommence in 2000-01, following the arbitration process (which according to some stakeholders served to cleanse IPTL and the sector of alleged corruption); it had been proven that Tanzania's demand growth could absorb capacity from both plants; and following justifications by MEM.²⁸⁷ Although the root cause was the IPTL dispute, during the time that Songas was postponed, the AFUDC accumulated, reaching over US\$100 million by 2003. Furthermore, all procurement processes were aborted and then restarted. While the project may not have happened without Bank support, the presence of the Bank led to a very distinct set of outcomes.

The GoT, Songas' largest lender (on-lending the World Bank and EIB funds to the project company) has supported the project extensively. The financing agreement was that the World Bank would on-lend to the Government of Tanzania, which would in turn on-lend to the project at a higher rate, in an attempt to move TANESCO toward commercialization. With TANESCO facing financial constraints, particularly since May 2005, the terms of finance have been readjusted, as per the 2001 subsidiary loan agreement, with government accepting a postponement of interest and principal. This agreement is presently reducing TANESCO's

²⁸⁷ The World Bank exerted significant pressure on GoT to cancel the IPTL plant. According to MEM and World Bank personnel, the Bank made no attempt, however, to cancel the Songas project for the following reasons: it fit the Power System Master Plan; cost of production was comparatively favourable; and there were no allegations of corruption.

capacity charges to Songas by almost half. It is an arrangement that could not have happened under a commercial bank agreement, which would have most likely resulted in project default (then again, no commercial banks were available to lend to the project at the time of financing).

While the terms and conditions of the concessionary loan are currently making Songas less expensive, the buy-down of the AFUDC on the part of the GoT has also contributed to lower costs for the utility. Without the buy-down, TANESCO would currently be facing charges of US\$6 million per month for turbines I-IV.

A final factor in ‘making’ the Songas project is the equity turnover and the emergence of Globeleq as lead shareholder. Globeleq’s appetite for risk, which may be largely a function of its lower cost of capital, combined with its knowledge and experience in Tanzania has meant that the project materialized even after TransCanada and AES grew sour on the investment.²⁸⁸

6.6.4 Disputing and depending on IPTL

IPTL reveals an equal range of factors that have affected outcomes. Project partners have also made a significant imprint on the project as has the project finance and the fuel type and agreement. Among the most visible factors related to IPTL, however, has been the allegation of corruption. According to numerous stakeholders, it was bribery that helped seal the deal between IPTL and the GoT, causing inflated project costs, postponement of Songas, and ultimately arbitration and subsequent delay of IPTL. An attempt by TANESCO to cancel the plant based on corruption, however, failed, and the utility did not pursue further investigation, as offered by ICSID. Similarly, an investigation into corruption led by GoT was completed, but charges were never pursued. The legacy of the alleged corruption is that today Tanzania has a plant with construction costs that are among the highest for similar size/technology IPPs in the developing world for no particular reason (other than poor planning and/or execution). On the other hand, it has a plant that did reduce the country’s load shedding during acute power shortages, serving as an important insurance policy, and has since been termed “a saviour”, even by stakeholders who indicate that corruption was likely.

In terms of the project partners, local partner VIP took IPTL to court shortly after the plant commenced commercial operations due to oppression by the majority shareholder, alleged business fraud and failure by Mechmar to contribute equity. VIP has also since objected to an attempt by IPTL to devalue VIP’s shares. The dispute, which reflects the poor investment outcomes for the local partner, may also ultimately impact on the project debt, due to the fact that VIP has petitioned to cancel the recent sale of the project’s debt to Standard Chartered.

²⁸⁸ Stakeholder in GoT have indicated that Songas would have gone ahead after AES’s exit even without Globeleq or a ‘Globeleq type firm’. At the time that AES exited, construction was nearly complete. GoT would therefore have completed construction with funds from the escrow facility. Furthermore, provided AES had not found a willing buyer and opted to leave the project, the GoT would not have been required to pay down the AFUDC. There would be no ROE expected and the capacity charge would have dropped to US\$2 million for the original scope (turbines I-V).

Project financing, which was initially hard to come by, is at the root of the local partner's dispute, with VIP arguing that the project was financed 100 per cent by debt. IPTL management counters this allegation insisting that Mechmar did contribute equity, but the project became highly indebted during the arbitration period (1998-2001) and therefore the project was required to devalue shares. As of the writing of this report, these issues remain unresolved.

IPTL's use of fuel is equally contentious. Although conversion to natural gas was specified in the 1995 PPA, the plant continues to run on HFO, which means the energy charge is at least 25 per cent more expensive than it would be if it were running on domestic gas sourced from Songo Songo. Although initially the most common reason cited for the delay in conversion was the lack of precedent, as the specific type of engine has never been converted before. Here again, however, poor planning and execution among the diverse stakeholders has played a serious role, together with the ongoing disputes and negotiations related to the project's debt and equity. Signs now point to the fact that GoT will purchase the debt, and most probably the equity as well, with conversion slated thereafter (provided there is sufficient capacity at the gas processing plant). Mothballing remains a remote possibility for this plant in the interim.

In closing, it is important to emphasize that although charges have been remarkably high, they do remain less than the cost of unserved energy, and therefore do not negate the more recent perception (throughout much of 2005 and 2006) of IPTL as a well run plant that has saved the country from power shortages.

6.7 Conclusion

Tanzania's IPPs were born out of the push for private participation, led primarily by the World Bank, and supported by international consultants and domestic champions of the new model for power sector reform. IPPs were only one part of the reform package, which, as initially laid down in the Power VI project, tied the development of the 180 MW Kihansi Hydropower station to power sector reforms, including plans for restructuring the sector and introducing of private participation into both power and natural gas development. A duplication of IPP efforts, however, ultimately undermined the effectiveness of the plants and may have been among the significant contributing factors for slowing reform plans, including TANESCO being removed from the list of utilities specified for privatization.

In the end, neither the IPP development outcome nor the investment outcome has been stellar. Furthermore, no balance appears to have been achieved between the two, which has translated into a sense of precariousness with regard to individual projects as well as how IPPs relate to the sector, rather than any sense of long-term sustainability. Interestingly enough, however, the general perception by the public and public sector is that the outcome for

investors has been highly profitable (at the country's expense), whereas most investors see the development outcomes as far outweighing any investment rewards. There is general agreement, however, that Tanzania's gas industry is developing, which is a benefit to stakeholders across the board, due to lower fuel prices and greater security of supply.²⁸⁹

The IPTL arbitration, which in turn led to contract changes, was prompted by a perceived imbalance between the development and investment outcomes, namely that investment gains weighed too heavily against the country stakeholders. However, the aftermath of the arbitration has still not brought a complete sense of satisfaction to the deal makers. Changes to Songas' capacity charges via the buying down of the AFUDC also led to a greater balancing, however, in contrast to most other rebalancing acts, it was the government (rather than the sponsor) that made the compromise by absorbing what would have otherwise been passed on to the rate payer.

The suboptimal developmental outcomes may be attributed to the investment climate and the perceptions of risk, poor planning processes, no clearly articulated private power framework, together with the lack of regulatory oversight and possible corruption. Factors contributing to the suboptimal investment outcome appear to be primarily related to project delays, which may be linked in turn to allegedly corrupt or poor business practices and poor planning and execution. Project sponsors together with a unique set of financing arrangements have also made significant impacts on outcomes along with the fuel arrangements for each plant. Projects have survived these stresses through equity turnover, and refinancing. A striking feature of Tanzania's IPPs is that none has failed outright. Instead, government stakeholders have intervened to buoy projects, including, as mentioned above, via the buying down of Songas' AFUDC, and firms such as Globeleq have identified projects as new market opportunities.

Despite the mixed results, the MEM together with TANESCO indicated, in the first quarter of 2006, that they planned to put more IPPs on the ground. At that time, although the terms and conditions were not determined, officials insisted that they would be different from those for the existing plants. What ensued, however, was a deal struck with Richmond, which as noted in section 6.2, ultimately only delivered the contracted capacity once GoT intervened to help airlift the engines. Kiwira coal mine has also failed to deliver, after not raising the necessary finance. Once again, emergency power was brought in to plug shortages. Although conditions were to be different than those of existing plants, procurement processes for neither Richmond nor Kiwira followed international competitive bidding processes, with EWURA providing no oversight due to the fact that it came into existence only after the fact. In the case

²⁸⁹ With prices capped at 75 per cent the liquid fuel equivalent, however, there is a risk that investors may not see a clear incentive for future development of the field. Orca Exploration has not, however, indicated any such concern.

of Richmond, again, corruption allegations were made, which although since cleared, still raise doubts about due process being followed.

If the case were not clearly made with IPTL and Songas, it appears today that there is a powerful need to enumerate the lessons of the past and be cognizant of a coherent way forward to ensure sustainable outcomes.

Chapter 7

Synthesis and conclusions

7.1 Recapitulation

The story of Independent Power Projects in developing countries is not a simple one. Initially conceptualized within the broader context of power sector reform, these projects were intended to relieve state utilities of the burden of financing new plants, bring quick, quality power and reduce costs for end-users. Actual implementation of projects has, however, been intertwined with controversies, delays, and debates over costs of power. In many developing countries, IPPs have not lead to either quick or cheap power. States previously haunted by issues related to insufficient public funds are now grappling with critical issues related to affordability. Additionally, several IPPs were negotiated with the aim of alleviating immediate crises and needs, and were often only loosely connected to sector reform plans and policy models. In numerous cases, IPPs have been a lightening rod of national and international debate and have led to rethinking of reform policies and the role of private sector participation by both advocates and critics of IPPs. A number of IPP projects globally have also either been re-negotiated or cancelled. IPPs offer a critical opportunity to glean lessons for reform and private sector participation in the power sector.

This thesis has sought to evaluate the African IPP experience by focusing on development and investment outcomes and the extent to which such outcomes are in balance. The central question has been whether a balance between these two outcomes ultimately improves the sustainability of IPPs. Efforts have also been made to unearth what may be the contributing elements to such sustainability or success, particularly given a suite of exogenous stresses. Throughout, this thesis has repeatedly drawn on both the power sector reform context, especially the extent to which the standard model was applied, as well as the potential for the obsolescing bargain to further elucidate the understanding of how and why African IPPs developed as they did.

This final Chapter has three main goals: first, to provide an analysis of the balance between outcomes across the pool of projects evaluated; second, to systematically review the exogenous stresses as well as the factors that contributed to success, and finally to reflect on the overall theoretical and analytical framework for this thesis, namely the role of power sector reform and the obsolescing bargain. Although the majority of examples are based on the IPP experiences of Egypt, Kenya and Tanzania, as treated in Chapters four through six, efforts are also made to incorporate data from a larger pool of experiences, namely those of Cote d'Ivoire, Ghana, Morocco, Nigeria, and Tunisia, as profiled briefly in Chapter three.

7.2 Reviewing the balance

Detailed reviews of nine IPPs in three African countries have been completed, and another 11 privately sponsored generation projects have been considered across a further five countries. The tally is small, but amounts to 80 per cent of the total African IPP investment and 75 per cent of the continent's IPP capacity, installed since the 1990s. Of the larger project pool of 20 IPPs (detailed in Table 3.1), there is scant evidence for projects unravelling, in contrast to the international experience, even in adverse and unexpected circumstances such as currency devaluation and civil strife.

Instead, across North Africa, there is considerable evidence for all original deals holding in their entirety (with the exception of Tunisia's SEEB project), which has been largely credited to the greater balance between development and investment outcomes, that is, the achievement of both affordable, reliable power and reasonable investment returns.

In the East and West African cases examined by this thesis, contract changes have been more numerous. For example, Kenya's Iberafrica voluntarily reduced the capacity charges in its first PPA. OrPower4, also of Kenya, finally agreed in 2006 to drop the price of its tariff for its second phase of 35MW, which represented a departure from terms agreed to originally in 1998. In Tanzania, IPTL, the country's first large-scale IPP, went to arbitration over what were deemed unreasonably high costs, with the settlement shaving about US\$30 million off the total capital costs. The buying down of Songas' AFUDC (of approximately US\$103 million) by the Government of Tanzania cut the monthly capacity charge by about one third.²⁹⁰

In West Africa, Nigeria's Enron/AES plant faced a renegotiation after complaints intensified about high capacity charges and the project's fuel choice. The Okpai project is also undergoing a renegotiation, with parties presently in disagreement about the final investment cost, which has ramifications for the capacity charge. As with OrPower4, Iberafrica and AES Barge, the dispute has not been elevated to international arbitration. Surprisingly, Cote d'Ivoire, despite civil war, has been free of any such renegotiations, as has Ghana. For Ghana, however, a special note must be made; two of the projects that were expected to become IPPs (in the case of SIIF Accra, by extending its contract, and in the case of Osagyefo Barge, by inviting private participation) never produced a kilowatt of power. The second phase (110 MW) of Ghana's Takoradi II has also not materialized due to a disagreement over costs and lack of guarantees. In addition, it should be noted in this context that Kenya's Westmont project, although not unravelling per se, did not negotiate a second contract, in contrast to

²⁹⁰The buying down of the AFUDC, which was negotiated by the Government of Tanzania during AES's sale to Globeleq, has not, however, negatively impacted on the sponsor since the full amount of the buy-down was paid to Globeleq. In addition, since May 2005, TANESCO has not been paying the portion of the capacity charge that relates to the project's subordinated debt. Although such an arrangement was provided for in the subsidiary loan agreement of 2001, what this means is that the IDA credit that the Government of Tanzania on-lent to TANESCO at a higher rate is presently not being serviced by the utility.

Iberafrica, after agreement on tariffs could not be reached between parties. In contrast, Kenya's Tsavo appears to have resisted pressure to lower its tariff, with its 20 year contract intact.

In sum, of the 12 Sub-Saharan IPPs evaluated, seven underwent some form of contract change. The figures are even more dramatic if one focuses exclusively on East Africa, where five of the six projects evaluated have seen changes to the original deals. To reiterate, however, is the equally if not more noteworthy fact that none of the contracts have actually unravelled.²⁹¹

In virtually each case, the contract changes cited above appear to be prompted largely by what is seen as an imbalance, on the part of the host country, in outcomes, which is often exaggerated by a suite of exogenous stresses, including electricity shortages caused by drought in hydro-dependent systems. Generally, tariffs are deemed too high to be sustainable over the long-term. Investment outcomes have come at the expense of development outcomes. The subsequent balancing ultimately appears to introduce a greater level of sustainability to the project. As one investor has noted, "It is not the best possible outcome. We have compromised, but it is a happy ending. We now have amicable terms with [the state utility], and a decent investment."

What has led to the original balance between outcomes in the majority of North African cases? Furthermore, to what may the absence of such balance in most of the Sub-Saharan cases be credited and the greater attainment after original deals were signed? Did the obsolescing bargain in fact play a role, and the new protections not work as expected?

The following sections review just what exactly contributed to success in the North African IPPs as well as what may have led to greater success and what could enhance sustainability in IPPs throughout Sub-Saharan Africa. Sections are both descriptive and prescriptive, describing what host country governments and sponsors did, and what they could have done to achieve more favourable results.

A final note should be made that while sustainability has been achieved through either an original balancing of outcomes or an eventual balancing after changes have been made to original contract terms, this does not mean that projects have been replicated. Egypt, despite its development and investment successes, has seen only three IPPs. The terms of any future IPPs will be markedly different from the existing ones. Thus the focus is on the sustainability of the particular project, not on a platform of projects, which raises more questions ultimately about IPPs within power sector reform.

²⁹¹ However, as noted above, Westmont did not renew its contract, and two projects in Ghana, SIIF Accra and Osagyefo Barge, although not fully IPPs, never produced any power.

7.3 Building up the contributing elements to success, at the country level

7.3.1 Favourable investment climate

The investment climate is not a deal breaker per se. IPP investments have been made in challenging contexts, most notably Kenya, which faced an aid embargo during its first wave of IPPs. However, the investment climate determines the degree of interest by foreign investors and hence the competitiveness of bids and ultimately the cost of the projects. The most favourable investment climates have been characterized as those with macro-economic stability, an active capital market, an efficient banking system, a history for upholding contracts and where recourse to arbitration is easily available. The relative absence of corruption, the availability of a well educated and productive labour force at reasonable rates and a growing economy with a focus on increasing the private sector's role also contribute. Finally, the financial health of the power sector, namely the solvency of the off-taker, together with the prospect of more than one investment may mean that less costly risk mitigation techniques may be required and that the cost of capital is reduced and reflected in the target return on equity.

Egypt, Morocco and Tunisia distinguished themselves from their Sub-Saharan Africa counterparts, with Tunisia scoring the highest in terms of its investment track record as evidenced by its investment grade ratings for foreign currency (BBB) and local currency (A). Both Egypt and Morocco score just one notch below investment grade (at BB+).

In contrast, the Sub-Saharan IPP sample has no investment grade ratings. Of the three countries that have received a speculative grade rating (Ghana, Kenya and Nigeria), two of these ratings (Kenya and Nigeria) were given in the last two years, long after IPP deals were signed, with Kenya's investment climate defined by its aid embargo in the mid-1990s, as previously noted. Furthermore, Ghana's speculative rating (at B+) is four notches below investment grade and therefore not comparable to the speculative grade ratings of Egypt and Morocco. Tanzania is also worth mentioning in this context. Throughout the 1990s, all export credit agencies were off-cover in Tanzania; no foreign commercial banks were willing to lend, as there was no clean track record of commercial loan repayment. Consequently, the possibility for a traditional project-financed IPP deal in this climate was limited. To summarize, for each of the three North African IPP success stories described here, countries have either had an investment grade rating or one notch below, in contrast to the five Sub-Saharan Africa IPP cases, where no country has received an investment grade rating and even speculative grade ratings have been few and far between.

Furthermore, despite the difference in the perception of the investment climate between North and Sub-Saharan Africa, incentives offered to investors in IPPs were relatively similar across the pool of eight countries and 20 projects, with some variety with regard to tax

breaks.²⁹² For instance, nearly all 20 projects appear to have benefited from both customs and VAT exemptions during construction as well as full repatriation of profits. Currency conversion was also provided for in virtually all of the projects. In terms of tax holidays, all three countries in the North African sample had tax holidays of five years. In East Africa, Tanzania provided a tax holiday of five years, but Kenya's tax holidays only extended until plant commissioning. Although one would expect the investment incentives to increase with the perceived risk (with increased incentives offered in Sub-Saharan Africa), such a pattern is not evidenced.

How did the perception of the investment climate impact on project development? Quite simply, with demand for IPPs outweighing supply, those countries with a better investment profile (primarily the North African sample) attracted more investors and ultimately were able to cement deals on more favourable terms to the host country. While not the only factor in influencing outcomes, the investment climate context goes a long way in setting the stage for negotiations and more balanced contract terms and helps explain the initial imbalance in so many of the Sub-Saharan cases.

7.3.2 New policy frameworks and regulation

An ideal framework involves a clear policy statement backed by legislation that: elaborates where and how power sector developments fit into overall energy policy; clarifies the governance of state-owned utilities (including corporatization and commercialization, transparent ring fencing of costs and adequate cost-recovery, together with a plan for possible unbundling); and makes room for private sector participation, including IPPs. Furthermore, the framework with regard to IPPs, ideally: defines the relative role of IPPs and the incumbent state-owned enterprise; specifies how IPPs will be procured and which agency has responsibility; introduces international competitive bidding standards; establishes an independent regulator and defines the powers and functions, among them the licensing of IPPs and approval of PPAs, including pass-through costs, and dispatch rules.

Although all eight countries in the sample have introduced legislation to allow for private generation, few countries have actually formalized and then realized a clear and coherent policy framework. Thus there is abundant evidence of tentative experimentation with private power that does not always lead to a sustained opening of the electricity market for private investment. Furthermore, long-term PPAs have the potential to constrain wholesale competition in the future, as forewarned in section 2.7.1, although means to transition to wholesale competition with IPPs have also been identified (Woolf and Halpern 2001). In

²⁹² Although many investment incentives were similar, there was considerable variation in terms of the security arrangements and credit enhancements that firms negotiated, including within specific countries as will be highlighted in section 7.4.3.

addition, state-owned utilities are rarely exposed to market costs of capital and direct comparisons of their costs with IPPs are often difficult to discern.

Nowhere is the standard reform model for power sector reform being adopted full-cloth, namely unbundling of generation, transmission and distribution, introducing competition and private sector participation at both the generation and distribution level (the question of whether such a model is ultimately relevant will be tackled in section 7.7) (United Nations Environment Programme and United Nations Economic Commission for Africa 2006:67; Malgas, Gratwick et al. 2007a; Malgas, Gratwick et al. 2007b). All utilities evaluated were 100 per cent state-owned with the exception of the Kenyan utility, which is owned 48 per cent by the state, and the Nigerian utility, which is in the process of being privatized (however, this development occurred after the two contracts evaluated in this thesis were bid, and PHCN still maintains a coordinating role).²⁹³ Thus, state-owned utilities remain in a dominant place, with IPPs on the margin and the future frameworks in many countries as of yet undecided.

The most coherent policy framework exists in North Africa, with Egypt defining itself as the frontrunner. In Egypt, 15 IPPs were specified by the EEA (later the EEHC), which was clearly charged with carrying out the IPP programme following ICB practices. IPPs were to provide the majority of new generation capacity to the grid. They were also to assist in benchmarking state-owned and operated plants and improve the overall performance of the sector. A regulator was to be integrated into the ESI and assist in oversight. Corporatization and commercialization of distribution assets was to follow. Of the numerous features of the policy framework, it was perhaps the clear mandate given to the EEA/EEHC to procure IPPs that helped define its early success. Even with a clear policy and the power to implement decisions, however, Egypt's IPP programme was derailed (after the first three plants were bid out), due to macroeconomic shock and a severe currency devaluation. In shelving the remaining plants, the government sought to reduce additional foreign exchange risk. Furthermore, reform of the incumbent state-owned utility has been slow. Thus, policy was either not implemented or was rewritten during implementation, a practice evidenced across the sample, with the present policy framework in Egypt favouring a return to publicly-financed generation.

While more piecemeal than Egypt, Kenya's policy framework has yielded one element that the other seven countries in the sample have presently parked or only pursued late in the game, namely the establishment of an independent regulator to aid in sector oversight. In Kenya, the regulator, together with the adoption of ICB practices, has helped to radically reduce PPA charges (between the first set of IPPs negotiated and the second). Kenya's ERB

²⁹³ In addition, it should be reiterated in this context that Cote d'Ivoire has had its state utility under a concession contract since 1990—an arrangement that is expected to continue until 2020. Tanzania has just completed a management contract of four years, and Kenya has just begun one.

has also been instrumental in helping to set tariffs and manage the overall interface between private and public sectors. In Cote d'Ivoire, Egypt, Ghana, Nigeria and Tanzania regulatory agencies have come into force only after IPPs have been negotiated, and there has been little impact as of yet, with, in the case of Egypt, the regulator's powers severely limited. Finally, no attempt to establish a regulator has been made in either Tunisia or Morocco, with the ministries the de facto regulators in these two countries. What has emerged as a general trend is that the mere presence of a regulator is not in and of itself a defining factor. An independent regulator may have positive, negative or no impact on outcomes, as previously indicated in both sections 2.7.1 and 3.2.4. If, however, regulatory governance is transparent, fair and accountable, and if regulatory decisions are credible and predictable, then there is greater potential for positive outcomes for host country and investor alike. Evidence also points to the fact that effective regulatory oversight may lead to a reduction in the stated capital costs of projects for selectively bid projects (Phadke 2007:10,25).²⁹⁴

A final policy and practice is worth noting in this context: in three of the eight sample countries (Nigeria, Tanzania and Tunisia) efforts have been made to exploit stranded gas as part of the IPP programme.^{295 296} In Nigeria, a reduction in gas flaring is central to the push for gas-fired power. In Tanzania, the IPP programme commercialized previously stranded (although not flared) gas via Songas and Mtwara. In Tunisia, although the primary goal was to attract new investment into the hydrocarbon sector, one significant spin-off has been the reduction of gas flaring. Each country has seen a distinct set of challenges,²⁹⁷ however, generally this larger policy has insulated projects from intense public scrutiny with project sponsors and policy makers alike able to point to the benefits of the commercialized gas and the reduction in fuel imports.

As first documented in Chapter two and will be assessed in greater detail in section 7.7, behind many of these policies sit the development finance institutions, notably the World Bank, which has had a hand in nearly all power sector reform programmes in Africa. These institutions were particularly instrumental in advancing private sector participation in generation. As many of those same institutions began reconsidering publicly-funded

²⁹⁴ Furthermore, alternatives to strictly independent regulation are increasingly being considered, which may provide a better match to a country's regulatory commitment and institutional and human resource capacity. Alternatives include: regulatory contracts, the outsourcing of regulatory functions, expert panels and regional regulators (Eberhard 2007:14).

²⁹⁵ Domestic gas reserves were used for IPPs in both Cote d'Ivoire and Egypt, however, unlike for the other countries mentioned above, this did not represent the establishment of a new gas infrastructure.

²⁹⁶ An attempt was also made to exploit stranded gas reserves in Ghana's Osagyefo Barge project, which, as described in Chapter three, however, has been led by the state, with as of yet no private participation, and no power produced

²⁹⁷ In Tunisia, gas quality has proven poor and water also flooded the wells; consequently the plant has been repeatedly offline; in Nigeria, although the gas is of good quality, stakeholders have seen costs escalate which in turn has caused the utility to withhold payments. In Tanzania, costs have also escalated, but for reasons unrelated to the gas project itself.

infrastructure investments again at the end of the decade, countries have often followed with policies that reflect this movement—from state to market and back again.

For many of the sample countries, however, the future framework remains uncertain, even as there appear to be more concessionary loans available. As one policy maker indicated: “The government is reviewing the impact of IPPs and the trend in countries like [ours]. [The utility] needs a breathing space. Soon[er] or later, the government will publish a strategic paper on the way forward.” In the meantime, in this same country, emergency power has been ordered to plug an immediate power crisis, as will be further explored below.

7.3.3 Coherent power sector planning and execution

Intricately connected to sound policy frameworks are coherent power sector plans. Ideally, the latter follows from the former and includes four components: setting a reliability standard for energy security; completion of detailed supply and demand forecasts; a least cost plan with alternative scenarios; and clarifying how new generation production will be split between the private and public sector as well as clarifying the requisite bidding and procurement processes for new builds. Among the most important aspects of coherent power sector planning is vesting planning and procurement in one empowered agency to ensure that implementation takes place with minimal mishaps.

The sample evaluated in this thesis has several noteworthy planning mishaps. In evidence are examples of demand and supply not being accurately forecast due partly to extended droughts, which in turn necessitated fast tracking IPPs, i.e. plants were sped through to meet immediate power shortages. The first two plants in Kenya (Westmont and Iberafrica), the first plant in Nigeria (AES Barge) and Ghana’s IPP were negotiated amidst drought conditions. Generally, the speed was at a cost. Although both Westmont and Iberafrica came online within eleven months, later they were the source of scrutiny and investigation (due to un-transparent bidding practices and what were perceived as unnecessarily expensive charges). Furthermore, Westmont did not secure a second PPA due to disagreement over a tariff, with public stakeholders unwilling to make similar concessions a second time. In the case of Nigeria, although fast-tracked, the AES Barge took nearly two years to come on line due to a renegotiation of the PPA.

An inability to accurately estimate demand and supply as well as set a clear reliability standard has also necessitated several cases of emergency power where units have been ordered for one to two years with the purpose of plugging a short-term power crisis. In both of the East African countries in this sample as well as Ghana, the governments have ordered units to address drought and system collapse. In Kenya, the country harnessed 100 MW of emergency power twice: in 1999-2001 and again in 2006 (supplied by Aggreko, Cummins and Deutz in the first instance and Aggreko alone in the second). Emergency power has been turned to

repeatedly in Tanzania also. In Ghana, emergency power was instrumental in reducing the impact of the 1998 drought, but with drought conditions reversing, the state failed to honour its contracts with SIIF Accra, which as of 2007, seven years later, remains an unresolved conflict. Costs for this emergency power, at approximately 30-40 US cents/kWh, are high, however, they are still less than the cost of no power (IFC per com 2005). As previously noted, Tanzania has estimated that it has saved around US\$1.00 for every kWh of outage averted (or about five to 10 times the ordinary cost of generating electricity).²⁹⁸

In Tanzania, the speeding through of one plant, described in Chapter six, has resulted in perhaps the most high profile IPP story on the continent to date. In this project, absent are critical planning elements, namely the lack of: a clear reliability standard, an accurate demand and supply forecast, a detailed plan for privately powered and publicly powered generation and most importantly a defined agency to implement the plan.

The Songo Songo gas-to-electricity project was in the Power System Master Plan, initially slated to come online within six months. However, the project was slow to materialize given its technical and financial complexity. With deadlines passing and power cuts persisting, it is alleged that other ministries, affected by the power cuts, started second guessing that TANESCO and the Ministry of Energy and Minerals, following the World Bank procurement procedures and relying on concessionary loans, would be able to deliver the project on time to address the shortages. As noted previously, the cost of unserved electricity to the economy was high and therefore Tanzania paid dearly for no power. Thus, the backdrop of the IPTL agreement appears to have been a failure to deliver on the Master Plan and hefty associated costs for many Tanzanians facing loss of services, TANESCO facing loss in revenue, and the Tanzanian economy facing loss of productivity, together with a clear interest in collaborating with Malaysian investors in the context of South-South partnerships.

The impact of this planning mishap was multi-fold: IPTL, which was negotiated quickly, behind closed doors, announced its total investment costs as US\$150 million (US\$163 including fuel conversion), which the Government of Tanzania and the World Bank would later argue was inflated by 40 per cent. This argument would in turn lead to a lengthy arbitration process spanning three years. During the time that IPTL was being disputed, the Songo Songo gas-to-electricity project would be put on hold, mainly through pressure from the World Bank, its largest donor, due to alleged corruption in the sector. Although the arbitration would ultimately lead to IPTL's investment costs being reduced to US\$127 million, the cost was still above and beyond the price that the government sought to pay. Furthermore, due to the delays, Songo Songo accumulated US\$100 million in interest charges on owner's equity, i.e. which the

²⁹⁸ In terms of international norms, however, it should be noted that Tanzania's cost of unserved energy (CUE) is low. South Africa's CUE is approximately US\$10, which is in line with the CUE in many industrialized countries (Global Energy Decisions 2007).

sponsor was owed by TANESCO. Additional costs to the state include emergency power that was required due to both IPPs being unavailable until 2002 and 2004, respectively.

Although it is easy in hindsight to accuse stakeholders of acting imprudently in the face of emergencies, the actual conditions of load shedding and shortages appear to have provided few alternatives. The solution appears to be in: taking steps to improve the investment climate, drawing up and implementing clear policy frameworks, (namely spelling out where and how private power fits into a single buyer model), building contingencies into the planning process, vesting planning in one agency, and conducting open bidding but under less cumbersome bidding procedures—all much easier said than done, but not infeasible for host countries to adopt and thereby move one step closer to balancing development and investment outcomes.

7.3.4 Competitive bidding practices

While policy and planning frameworks go a long way in determining outcomes, the type of bidding has been linked to outcomes, with considerable attention paid to the importance of international competitive bidding practices over selective bidding practices. Two recent studies, cited in section 2.7.1, have evaluated the relationship, demonstrating that while there is evidence for ICBs leading to up to a 60 per cent reduction in the stated capital cost of plants, there is also evidence for selective bidding proving effective in certain instances, provided there is regulatory scrutiny (Deloitte Touche Tohmatsu Emerging Markets Ltd. and Advanced Engineering Associates International 2003; Phadke 2007).

ICBs were conducted for 11 of the sample of 20 IPPs, including all three projects in Egypt and Morocco, and one of the two projects in Tunisia. In the East African group, ICBs have been less common, with three of the seven projects (OrPower4, Tsavo and Songas) recorded as having conformed with such bidding practices. In West Africa, an ICB was conducted for only one of the five projects (Azito).

In terms of gleaning meaning from ICBs versus selective bidding, of the six projects that have faced renegotiation, four of them were bid selectively rather than via an ICB (IPTL, Iberafrica, AES Barge and Okpai), with the two exceptions being Songas and OrPower4. The absence of regulatory scrutiny is noteworthy in each of these four projects as well. Furthermore, Westmont, which was selectively bid, quit the country after its first seven year PPA expired. The other selectively bid projects have also, with the exception of CIPREL and Mtwara, encountered some difficulty or another, which has led to a change in how the project is being developed.²⁹⁹ Ghana's Takoradi II has not been able to raise the finance for the second phase of the plant, and Tunisia's SEEB has not been able to secure its fuel supply and is

²⁹⁹ Although Tullow Oil, which initially won the contract to develop the Mnazi gas field in 1994, did encounter difficulty, this related primarily to the upstream portion of what is today known as the Mtwara Energy Project (see section 6.2). ATJL has indicated that since negotiations began in 2003 it has encountered no such difficulties.

presently offline. Although reasons for these stumbling blocks may be traced well beyond the presence or absence of an ICB, the correlation is nonetheless revealing.

Furthermore, it should be noted that the success of the ICB process is intricately linked to the number of bids received, with more bidding driving down prices. The number of bids submitted to ICBs in North Africa was generally double to triple those submitted to ICBs in East Africa--with only three bidders in Kenya's Tsavo plant and two in both OrPower4 and Songas plants. All three projects have since been pressured to lower tariffs, as discussed repeatedly. In addition, the time and associated cost required to complete an international competitive bid should not be underestimated, with drought related energy crises often cited as the reason why ICBs have been passed over. Just as alternatives are being considered for strictly independent regulation, including contracting out, to match the institutional and human resource capacity in a country, as discussed in section 7.3.2, the Sub-Saharan African examples here point to the need for more efficient bidding processes that while focussing on transparency and oversight also expedite timely outcomes.

7.3.5 Abundant low cost fuel and secure fuel contracts

The availability of competitively priced fuel supplies for IPPs has also emerged as a key factor in how IPPs are perceived and ultimately whether there is public appetite for more such projects, in large part because fuel is generally a pass-through cost to the utility and in many cases to the final consumer as well. Thus, if the IPP uses a fuel different from the incumbent fuel, and if that fuel is more expensive, then there is greater potential for stress on the project. In three of the sample countries (Ghana, Kenya and Tanzania), at the inception of IPPs, low priced hydropower was the dominant fuel source. In these countries, IPPs were thermal powered, using a combination of imported fuel oil and domestically procured natural gas. IPPs helped the countries to achieve greater fuel diversification, however, when the costs of IPPs (other than those running on domestically procured natural gas, namely Songas) were compared with state-owned, generally amortized hydropower, the new privately owned generation was seen to be largely more expensive, due partly to the energy/fuel charge. Furthermore, these countries witnessed a series of debilitating droughts over the course of the 1990s. Drought has also wreaked havoc throughout the East African region between 2002 and 2006. During this time, the existing hydropower infrastructure proved insufficient, and thermal, provided almost entirely by IPPs, was increasingly integrated into the fuel supply mix (from 10 per cent to 60 per cent in Tanzania), forcing up the price of power. Although more thermal power may be required, the public perception is that IPPs drive prices up, rather than a number of factors, including drought, which means that gaining public support for such projects is all the more challenging.

Contrast this story with Morocco and Nigeria. In Morocco, at the inception of IPPs, oil and coal, largely imported, were the incumbent fuels. Hydropower also played an important role in contributing to the generation mix. Through Jorf Lasfar, the country's first and largest IPP, Morocco changed its fuel composition; as of 2005, coal had become the dominant fuel, accounting for more than 60 per cent of generation. Although only 50MW, the country's wind power plant also contributed to the diversification, together with Tahaddart, which introduced over 300MW of natural gas-fired generation. Thus, like Kenya and Tanzania, Morocco has achieved fuel diversification through its IPPs, however, unlike the two other countries, Morocco has seen prices come down, due to a host of factors, including the relatively cheaper price of imported coal, and the use of gas via the Algerian-Spain pipeline, which fuels Tahaddart and which the government receives as a royalty.³⁰⁰ Nigeria has relied entirely on domestically procured natural gas, and gas is the incumbent fuel. Until recently, although a series of issues affected project outcomes, most notably the investment climate and bidding procedures, fuel had been of no issue; however, recent civil unrest in the Niger Delta has led to a disruption in the fuel supply.

At the beginning of this section, the claim was made that when IPPs use fuel that is either cheaper than the incumbent fuel and/or the same as the incumbent fuel, IPPs have a greater chance of success. There are, however, several noteworthy exceptions. Tunisia's SEEB plant is one such exception. Although natural gas is the incumbent fuel in Tunisia, the SEEB plant was part of an initiative to attract investors to exploit stranded gas associated with oil production. Thus, since SEEB's fuel supply has been compromised, there has been no other source of supply for the plant. In Tanzania, the natural gas from the Songo Songo field, which was dedicated to supply the Songas plant and later to fuel IPTL, is cheaper than the imported fuel oil presently powering IPTL. There have, however, been significant delays in fuel conversion of the IPTL diesel units. Finally, in the case of Egypt, natural gas is the incumbent fuel and also the fuel of choice for all IPPs to date. Fuel is a pass through to the utility, but presently not to the final consumer. Fuel is also subsidized. In the last few years, the country has emerged as the sixth largest LNG exporter in the world. Presently a debate is raging about how to allocate the remaining natural gas reserves. Should they go for additional electric power generation, LNG export, or present and future industrialization projects? The issue then is not simply whether a country has abundant, low cost fuel, but whether security of supply is guaranteed through fuel contracts well into the future (for up to 30 years in the case of Jorf Lasfar and on average 20 years for the other projects). Fuel must be abundant and low cost, both now and later, for it to have a positive, not negative, impact on outcomes.

³⁰⁰ Other contributing factors to a reduction in tariffs in Morocco include: economies of scale that Jorf Lasfar offers (in 2004, 66% of the country production was from one single plant), the reduction in government fuel taxes (undertaken at the start of IPPs to make tariffs more competitive with region) and the increased management efficiencies at ONE (technical as well as economic).

7.4 Building up the contributing elements to success, at the project level

Who were the investors and what did they do to navigate the varying investment climates as well as the changing policy and planning frameworks, including fuel supply? Starting with an evaluation of equity arrangements, this section examines trends in investor behaviour, and how investors secured revenue to service debt and reward equity, particularly in the face of exogenous stresses.

7.4.1 Favourable equity arrangements

Did the presence of local equity shareholders make a difference in project outcomes? Were projects with such participation less like to encounter the obsolescing bargain? How did a firm's prior experience with a country play out in terms of the making and breaking of deals? What about the presence of development-minded firms such as IPS and Globeleq as well as DFIs? Table 7.1 immediately below lists each of the projects, followed by the country origins of sponsors and their respective equity share, whether projects faced a change in contract terms and finally if there was turnover of the majority (Mj) equity partner.

Table 7.1: Equity participation in IPPs

Project (country initial)	Equity partners (country, % of equity held)	Change in contract terms	Mj ³⁰¹ equity turnover (#)
Sidi Krir (E)	InterGen (USA, 60%) & Edison (USA, 40%) sold to Globeleq (UK, 100%) in 2004-2005, conditional sale to PEL (JV between Malaysia Tanjong & Saudi Arabia Al Jomaih, 100%) in 2007	N	2
Port Said (E)	EDF (France, 100%) sold to Kuasa Power, subsidiary of Tanjong (Malaysia, 100%) in 2006	N	1
Suez (E)	EDF (France, 100%) sold to Kuasa Power (Malaysia, 100%) in 2006	N	1
Jorf Lasfar (M)	CMS (USA, 50%) and ABB (Swiss, 50%) sold shares to TAQA (UAE, 100%) in 2007	N	1
CED (M)	EDF (France, 49%), Paribas (France, 35.5%) & GERMA (France, 15.5%) maintained equity since 1997	N	0
Tahaddart (M)	ONE (Morocco, 48%), Endesa (Spain, 32%) and Siemens (Germany, 20%) maintained equity since 1999	N	0
Rades II (Tu)	PSEG (USA, 60%) sold shares to BTU Power Company (GCC ³⁰² , 60%) in 2004, Marubeni (Japan, 40%) retained shares since 1999	N	1
SEEB (Tu)	Centurion (USA, 50%) sold to Candex (Canada, 50%) in 2005, Caterpillar (USA, 50%) maintained equity since 2002	Y	1
Westmont (K)	Westmont (Malaysia, 100%) has sought to sell plant since 2004	-	-
Iberafrica (K)	Union Fenosa (Spain, 80%), KPLC Pension Fund (Kenya, 20%) since 1997	Y	0
OrPower4 (K)	Ormat (USA/Israel, 100%) since 1998	Y	0
Tsavo (K)	Cinergy (USA) & IPS (Int'l) jointly owned 49.9%, Cinergy sold to Duke Energy (USA) in 2005, CDC/Globeleq (UK, 30%), Wartsila (Finland, 15%), IFC (Int'l, 5%) retain remaining shares since 2000	N	1
IPIL (Ta)	Mechmar (Malaysia, 70%), VIP (Tanzania, 30% in kind), both have sought to sell shares	Y	-
Songas (Ta)	TransCanada sold majority shares to AES (USA) in 1999 and AES sold majority shares to Globeleq (UK) in 2003 ³⁰³	Y	2
Mtwara (Ta)	Artumas (Canada, 80%), FMO (Netherlands, 20%)	N	0
CIPREL (C)	SAUR International, with 88% (JV between French SAUR Group owned by Bouygues, 65% and EDF, 35%) BOAD, (West African Bank for Development), PROPARGO, (the Investment and Promotions Company for Economic Cooperation, subsidiary of AFD), and IFC holding the remaining 12%; in 2005 all shares sold to Bouygues (France, 98%), except BOAD (2%)	N	1

³⁰¹ Column indicates the number of times majority (Mj) equity share(s) traded hands, not minority. For instance in the case of Songas, majority shares have traded hands twice with three different lead sponsors, however, minority shares have been bought and sold many more times. See footnote 303 below for details on Songas.

³⁰² BTU is owned by public and private investors in the Gulf Cooperation Council (GCC).

³⁰³ Due to complexity, turnover is detailed in this footnote: Ocelot (Canada), TransCanada (Canada), TPDC (Tanzania), TANESCO (Tanzania), TDFL (Tanzania, sponsored by EIB), IFC (multilateral), DEG (German), CDC (UK) were shareholders by 1996, with TransCanada the majority shareholder; IFC and DEG sold shares to CDC in 1997/8; TransCanada sold shares to AES (USA) in 1999; Ocelot/PanOcean sold shares to AES in 2001; AES sold majority shares to Globeleq (UK) and FMO (Holland) in 2003. After the AES sale, equity shares and associated financial commitments (expressed in US\$ million) in Songas were as follows: Globeleq: US\$33.8 (56%), FMO: US\$14.6 (24%); TDFL: US\$4 (7%); CDC: US\$3.6 (6%); TPDC: US\$3 (5%) and TANESCO: US\$1 (2%). This does not reflect the additional US\$50 million that Globeleq committed for the expansion.

Azito (C)	Cinergy (JV between Swiss ABB, 50% and French EDF, 50%) holds 65.7% of shares, CDC/Globeleq (11%), and IPS (23%)	N	0
Takoradi II (G)	CMS (USA, 90%), VRA (Ghana, 10%), CMS sold shares to TAQA (UAE, 90%) in 2007	Y	1
AES Barge (N)	Enron (USA, 100%) sold to AES (95%) and YFP (Nigeria, 5%) in 2000	Y	1
Okpai (N)	Nigerian National Petroleum Corporation (Nigeria, 60%), Nigerian Agip Oil Company (Italy, 20%), and Phillips Oil Company (USA, 20%) maintained equity since 2001	Y	0

Notes: N: no change in contract terms and/or in original project concept as laid down in PPA, Y: yes change in contract terms and/or original project concept.

Foreign firms were the dominant player in African IPPs. There were no exclusively locally sponsored projects, unlike in Malaysia and China where local IPPs abound (Woodhouse 2005:22-23,91). This should not be surprising given the limited capital available in countries across the sample, however it is worth noting, and it does raise the issue of foreign exchange exposure, treated in section 7.4.2 below.³⁰⁴ Following this logic, there were only two projects in the pool in which local partners were the major stakeholder, Morocco's Tahaddart and Nigeria's Okpai. However, in both cases, the majority stakeholder was either the national utility or the national petroleum company. Furthermore, in the case of Morocco, ONE, the state utility initially intended to hold only a 20 per cent share and increased its share after EDF pulled out (Malgas, Gratwick et al. 2007a:16). In Okpai, the power project falls under the rubric of a state-led gas flaring reduction programme, in which international oil companies, presently operating in Nigeria, are being engaged in power projects. In the next such project, Afam, the Nigerian National Petroleum Corporation also has a majority share (of 55 per cent).

Local participation has been cited as a possible means to reduce risk (Hoskote 1995:11; Woodhouse 2005).³⁰⁵ A total of seven of the 20 projects had local equity participation, namely: Tahaddart, Iberafrica, IPTL, Songas, Takoradi II, AES Barge and Okpai. To what extent then did such local participation impact favourably on outcomes? Of the seven projects, six have encountered some form of change to their contract. Furthermore, in four of these six projects, either the state utility or another government entity held an equity share, which would indicate that the mere existence of a local partner might not be critical in setting an original sustainable balance. What about in the renegotiating of terms, how might a local partner make a difference? Kenya's Westmont and Iberafrica were both negotiated at the same time under similar policy frameworks. They are the only two examples in the project pool where one had

³⁰⁴ As first noted in Chapter three, projects such as Osagyefo Barge in Ghana and several projects in Nigeria (Ibom and Omoku) have been financed by either national and/or state governments and have been loosely termed IPPs for the following reasons. In Ghana, private participation was anticipated, and in Nigeria, projects have been independent of the national utility, led entirely by the Rivers State Government and the Akwa Ibom State Government, respectively. As of end-2006, however, Globeleq is "pursuing" investment in the Ibom project, which would include both investment in the existing capacity and an addition of up to 500 MW (Globeleq 2006:7).

³⁰⁵ Stanford PESD limits the benefits of local partners to "near-term and tactical business management, [the] study suggests that they play little role in grander tasks such as enforcing contracts," (Woodhouse 2005:98).

local participation (Iberafrica) and the other did not (Westmont). As has already been discussed, Iberafrica first voluntarily reduced its tariff and then went on to negotiate a second 15 year PPA, in contrast to Westmont, which quit after failing to come to agreement on a second PPA. The presence of a local partner may have helped in creating a longer term solution, however, with just one example, the evidence is not conclusive.

Origins, experience and mandate of partners

Although globally, IPP investments during the 1990s were led by a host of American and European investors who saw returns in their home markets diminishing, there was also a wave of investors originating from developing countries, particularly from Malaysia.³⁰⁶ In both Kenya and Tanzania, this thesis has profiled Malaysian firms committing to projects (including in one of the projects, Westmont, cited above where the firm took neither foreign nor local partners). In Egypt, EDF has recently sold its assets to Tanjong, a Malaysian firm, and Globeleq has entered into a conditional sale for its entire Asian and North African portfolio, which includes Egypt's Sidi Krir, to a joint venture between Tanjong and Saudi-based Al Jomaih.^{307 308} While it would be inaccurate to say that these firms overlooked the higher risk profiles of the African continent (and/or did not ultimately charge higher returns), there may have been a greater willingness to consider investments in the first place.

While the number of developing/emerging country-based firms appears to be growing, three of the southern-based firms are trying to sell their shares (Mechmar and VIP in IPTL and Westmont). Thus, the origin of the firm does not mean that project equity is set for life, or that such a firm is best positioned to service debt and reward equity since each of these sales appears to be motivated in part by an inability to do just those things.

A more revealing aspect than firm origins appears to be a firm's experience and mandate. Across the pool, examples pile up of firms being actively involved in the country prior to their IPP investment. For instance, EDF had a long-term relationship with Egypt in terms of providing technical assistance. Union Fenosa, the parent company of Iberafrica, had an existing relationship with Kenya through an IT contract. IPS, a major shareholder in Tsavo and Azito, had operated in Kenya since 1963 and in Cote d'Ivoire since 1965. CDC, from which Globeleq

³⁰⁶ Michael Schur, Stephan von Klaudy and Georgina Dellacha provide a preliminary analysis of the contribution of firms based in developing countries in infrastructure projects between 1998 and 2004, noting an overall increase and a particularly steep climb in transport investments by such firms. The authors conclude by indicating that the involvement of such firms is encouraging, however, the jury is still out on whether such firms are better positioned to deal with a host of complex political economy issues that characterize developing countries (Schur, Klaudy et al. 2006).

³⁰⁷ Another example of an emerging economy firm taking market share is BTU, based in the Gulf Cooperating Council, which bought shares from PSEG Tunisia's Rades II plant, in 2004.

³⁰⁸ There is evidence that Chinese and Indian firms may assume a greater piece of this market. India's Tata is among the bidders for South Africa's IPPs and Chinese firms are leading power projects in Sudan (Merowe dam project), and in Nigeria (Omotsho and Paplanto), (*China in Africa: from oil & gas to infrastructure* 2006).

was spun off, had a 50 year history in Tanzania. While the long-term presence of a firm does not appear to be decisive (as many such projects did face contract changes), it may help explain why more contracts did not unravel. Long-term relationships, with strong local management, previously cited in section 2.7.1 as a critical success factor and to be discussed in greater detail in section 7.4.6, appear to have contributed to the staying power of firms and often the rebalancing of contract terms.

The mandate of the firm also appears to play a central role in the investment decision as well as the terms of the deal. Until recently, the two firms that were increasing (rather than maintaining or reducing their stakes) were Globeleq and Industrial Promotion Services. Until May 2007, Globeleq held an 11 per cent share in Cote d'Ivoire's Azito, a 100 per cent equity stake in Egypt's Sidi Krir, 30 per cent equity in Kenya's Tsavo and 56 per cent in Tanzania's Songas. IPS holds a 23 per cent share in Azito, and together with Duke Energy, a 49.9 per cent share in Tsavo. IPS is also leading development of Uganda's Bujagali project, a 250 MW hydroelectric plant, which was formerly being developed by AES.

Although both Globeleq and IPS are driven by commercial interests, these firms have emerged from agencies with a strong commitment to social and economic development. Globeleq remains wholly owned by CDC, the private sector promotion arm of DFID. IPS is Aga Khan's Fund for Economic Development operating arm in the industrial sector throughout Asia and Africa. While projects for both firms must make commercial sense, they must also serve a clear developmental function for the country/community. It is this commitment to development that appears to be particularly helpful in the face of African risk.

None of the projects with involvement of such development-focused firms, save Tanzania's Songas, has seen any changes to contract terms, which may signal a greater perceived balance from project inception as well as a better ability to withstand public pressure. Furthermore, in terms of the Songas change, although the buying down of the AFUDC of US\$103 million brought about a reduction in the capacity charge, the firm received full payment upon the buy-down and therefore it represents a different case than many of the contract changes cited above.

An important development must, however, be reiterated in this context. Globeleq, which until 2006 seemed to be expanding its portfolio of assets, is in the midst of selling off the brownfield plants it bought to in turn position itself as a global, greenfield developer. The firm always intended to take this course, as it saw its brownfield investments as part of a stop-gap measure during the global downturn in private power. Recent, indicative bids for Globeleq's Sub-Saharan African assets were not, however, deemed viable and therefore for the time being Globeleq is holding on to its stake in Azito, Tsavo, and Songas. On the one hand, Globeleq's sale of Sidi Krir and its Asian assets signals that there may indeed be a renewed interest in private power. On the other hand, the absence of favourable bids for Sub-Saharan Africa

indicates that such renewed interest is still limited in scope (beyond supplying emergency power), and there may indeed be need for this type of development-minded firm in less developed countries.

Meanwhile the presence of DFIs persists in project equity. Although none of the North African projects saw such participation, four of the Sub-Saharan African IPPs saw DFIs pick up equity shares. IFC holds a 5 per cent share in Tsavo's equity. Until 2005, IFC also held, together with BOAD and the Investment and PROPARCO, a 12 per cent share in CIPREL. Both IFC and DEG had an approximately US\$12 million equity investment in Songas, with both organizations selling their shares after the IPTL dispute became known. FMO maintains a 24 per cent share in Songas (excluding the expansion of 65 MW) as well as a 20 per cent share in Mtwara. CDC, independent of Globeleq, also holds a 6 per cent share in Songas (excluding the expansion). It should be reiterated here that none of these projects, save Songas, has seen any contract changes.

Equity turnover

Equity turnover represents a final piece of this evaluation related to equity arrangements and how such arrangements have impacted on outcomes. Of the 45 original equity partners in the sample pool, 15 have exited from 11 different projects. This statistic, however, tells only part of the story. First, as previously indicated, three shareholders have been actively trying to sell their assets (both shareholders in Tanzania's IPTL and Kenya's Westmont) for several years. In the case of IPTL, Mechmar, the lead shareholder, has indicated that the arbitration settlement ultimately hurt equity partners, which has motivated the sale. VIP, the minority shareholder in IPTL, cites the following causes: oppression by the majority shareholder; fraud by Mechmar in inflating the IPTL capital cost; and failure by Mechmar to pay its equity contribution (i.e. the project was 100 per cent debt financed). There has been no resolution of this conflict, and no willing buyers. In terms of Westmont, the firm did not secure a second PPA, due to disagreement over tariffs and has, since 2004, been seeking to sell the asset. Second, if one focuses exclusively on majority shareholders, nine of the majority shareholders in the 20 projects have sold shares at least once and two of the majority shareholders have been actively seeking to do so for at least three years, as described above.

The repeated refrain from most sponsors is that the sale of assets is motivated primarily by changing circumstances in home markets and/or related to corporate strategy; that is, the sale has little to do with the host country actions and reactions and/or poor investment outcomes, namely the ability to service debt adequately and reward equity. As noted in Chapter four, InterGen's reason for selling its interest in Egypt's Sidi Krir to Globeleq in 2004 was based on the fact that its shareholders (Bechtel and Shell) made a strategic decision to move out of the business of owning and operating private power facilities. For Bechtel this meant moving back

to its core business of designing, engineering and building plants, but not operating and maintaining them, and for Shell, it meant focusing on the petroleum exploration and production business. Similarly, Edison has sold much of its global portfolio because of a decision to return to its core business in Italy. EDF also cites its plans of concentrating its investments in Europe. In terms of Tunisia's Rades II plant, PSEG described Tunisia as "an excellent place to do business" and noted that "the sale in no way reflects any unhappiness with [our] experience in Tunisia, but rather is in keeping with the company's stated strategy of reducing its international risks by selectively selling assets if they can obtain an attractive price" (Malgas, Gratwick et al. 2007b:15).

How does this refrain square with the contract changes? The majority shareholders in two of the eight projects that saw contract changes exited after such a change (namely, CMS in Takoradi II and Enron in what is presently known as AES Barge). Furthermore, as noted above, Westmont has sought to sell the plant since it failed to renegotiate a second contract, and Mechmar has actively been seeking to sell its shares post-renegotiation. In addition, although no contract changes are in evidence, one should not overlook the larger IPP programme change in Egypt. All three original sponsors have sold their assets, following the failure of the utility to follow through with 12 additional IPP projects as originally specified, which could have given existing sponsors a larger market share.

While less than expected investment outcomes may be partially motivating sales, turnover does not in and of itself appear to be challenging the long-term sustainability of contracts since in nearly all cases sellers have found willing buyers to take over the original or recently renegotiated PPAs. The two exceptions here again are the Westmont plant, where the first PPA has expired and which was shrouded in controversy and IPTL, which has been embroiled in lawsuits and therefore it may be understandable why the plants have not attracted buyers. One stakeholder went so far as to assert, "[equity turnover is a] healthy factor in a maturing market. It is a good sign when investors come and go – not a bad or threatening thing." The return of the government as shareholder, as planned in the case of Tanzania's IPTL as well as Globeleq's decision to hold onto its SSA portfolio, would, however, signal that some markets might actually be less mature than expected.

What in the end have been among the most critical characteristics of equity arrangements that have led to project sustainability? Overarching characteristics appear to be firms' prior experience in a country, the presence of development-minded firms and development finance institutions.

7.4.2 Debt arrangements: global and local

With debt financing covering often more than 70 per cent of total project costs, low cost financing has emerged as a key factor in successful projects. How and where to get this low

cost financing is the challenge, but possible approaches in the African cases lie in DFI involvement, credit enhancements, and some flexibility in terms and conditions that may allow for possible refinancing. The goal for sustainability appears to be that the risk premium demanded by financiers or capped by the off-taker matches the actual country and project risks and is not inflated.

While there is no uniform pattern in the debt financing for the projects considered in this thesis, there are a series of trends for how investors handled costs as well as practices that may ultimately contribute to success. Important to note at the outset is that although non-recourse project financing is the norm for privately financed electric power plants in developing regions, this sample of twenty projects saw several notable exceptions, including Nigeria's Okpai plant, which was 100 per cent financed by the balance sheet of equity partners, together with the second phase of Songas (however refinancing is presently being pursued in the latter case). Westmont, Iberafrika and OrPower4 were also all financed entirely with the balance sheets of their sponsors. For Westmont and Iberafrika, the reason cited for this arrangement was that insufficient time was available to arrange project finance as plants had to be brought online within 11 months. For Orpower4, reasons are linked, by the sponsor, to the lack of a security package, which was not forthcoming until 2006.

DFIs and their impact on projects

With limited appetite for projects among many commercial banks,³⁰⁹ development finance institutions are conspicuous in providing debt to projects across the pool.³¹⁰ Such entities participated in nearly every IPP, including significant participation on the part of the World Bank/IDA (CIPREL, Songas), IFC (Azito, Port Said, Suez, Tsavo), CDC (Tsavo, Azito), EIB (CED, Songas), DEG (Tsavo, Azito), FMO (Azito), African Development Bank (Azito) and PROPARCO (CED). In addition a number of export credit agencies were involved in providing financing: the USA Export Import Bank (Jorf Lasfar), OPIC (Jorf Lasfar), and JBIC (Rades II). Much of this involvement is related to the long history of DFI activity throughout Africa coupled with the real and perceived risks across the continent, which preclude private investors from filling the financing gap. The involvement is also, however, linked to the broader mandate of power sector reform, introduced in Chapter two, alluded to throughout this thesis and to be discussed in greater detail in section 7.7. Still, it is noteworthy that African IPPs, which by their very definition imply private investment, had such significant public involvement.

Although projects with DFI funding tended to take longer to reach financial closure, sponsors did cite clear benefits; multilateral and bilateral development institutions helped

³⁰⁹ A recent review indicates that Africa has attracted less non-recourse bank debt relative to private investment in infrastructure than other developing regions (Sheppard, Klaudy et al. 2006).

³¹⁰ See footnote 1 for a definition of development finance institutions.

maintain contracts and resist renegotiation in the face of external challenges such as Egypt's currency devaluation and Kenya's droughts when developers were pressured to reduce tariffs. A particularly revealing contrast is in the two Kenyan plants, OrPower4 and Tsavo, negotiated under the same policy framework, including via ICBs. The former plant saw no multilateral involvement in either its equity or debt whereas for the latter, IFC arranged all the debt and took a 5 per cent equity stake. Tsavo has since resisted pressures to reduce its tariffs by KPLC and the government, with the presence of a multilateral development institution cited as among the reasons. OrPower4 on the other hand has ultimately reduced its tariff for the second phase of the plant. Tanzania's Songas project, for which the World Bank together with EIB provided all the project debt, also deserves special mention here. The project took almost a decade to reach financial closure, but the World Bank played an instrumental role, in among other things, pressuring the IPTL arbitration, which ultimately led to what has been widely perceived as more balanced contract terms.

Locally denominated finance: the cost and benefit

Locally denominated financing appears to be among the solutions for more sustainable foreign investment, however, capital markets in many African countries are insufficiently deep or liquid to provide such financing for all projects. As previously noted, only one project across the pool, Morocco's Tahaddart, a 384 MW CCGT, negotiated a locally denominated PPA due to the fact that all of its debt (€ 213 million) was sourced from local banks. This local financing was aided by a number of factors including: the state utility's prominent role in the plant (holding nearly 50 per cent of total equity) as well as the fact that Morocco's commercial banks have a significant degree of state involvement.³¹¹ With or without state involvement, no other country in Africa, has, as of yet, managed to arrange this level and depth of financing for IPPs. Thus, Morocco stands as a pioneer in this respect.^{312 313}

The main drawback for IPPs without locally denominated finance may be seen as projects undergo the effects of macroeconomic shock and currency devaluation. In Egypt between the end of 2002 and early 2003, the currency lost half of its value and PPA payments in local

³¹¹ Banque Centrale Populaire (BCP) put up MAD1300m and MAD960m was extended by a consortium of banks consisting of BCP as the lead lender, the Banque Marocaine pour le Commerce Extérieure (BMCE) and Crédit Agricole (CNCA). Average exchange rate for the Moroccan dirham in 2003, the year that construction started, was 10.95MAD=1.00EUR (Interbank Rate).

³¹² Local currency financing has been recently employed by AES in Cameroon for the 80 MW Limbe power station. The local offices of Standard Chartered Bank, Ecobank, Afriland First Bank and the Commercial Bank of Cameroon provided short-term local currency financing for the AES project, which served as a bridge to longer term dollar denominated debt (The role of local banks in financing power projects 2005:1)

³¹³ Stakeholders involved in Namibia's Kudu gas-to-power project are also raising the possibility of local currency financing, which could slowly help to change the face of African power, by introducing a new level of financial sustainability for all those involved. Kudu involves commercializing domestic (Namibian) gas and the construction of an 800 MW plant, initially intended mainly for export to RSA.

currency terms doubled. In the short-term the US dollar and/or Euro denominated PPA represented among the greatest safeguards for sponsors, as equity and debt holders in Egypt did not see the value of their investments decline. The host country, however, paid dearly for the plants. Furthermore, one could argue that equity and debt holders did lose out indirectly due to the fact that a decision was made to cancel additional IPPs after the devaluation.³¹⁴ While no country other than Egypt in the sample experienced the crippling effects of macroeconomic shock, over the course of the decade, Ghana, Kenya and Tanzania saw serious creeping devaluation, with the currencies losing more than 100 per cent, 200 per cent and 400 per cent of their value, respectively, over the 1990s, which has inevitably had an impact on capacity charges.³¹⁵ There has been pressure to reduce such charges as well as to reconsider IPP development in each of these countries at different stages.

Although few projects have benefited from locally denominated financing, there are some promising signs, including in South Africa's IPPs. Sponsors for South Africa's two new peaking plants, totaling a combined 1000MW slated to come online in 2009, have been given access to the country's capital markets and capacity payments will be denominated in rand. Furthermore, as discussed in section 3.4.3, four Nigerian firms (Farm Electric, Supertek, ICS and Eithope) have all been licensed to build power plants as of August 2006 with the expectation that power will start coming on line from these firms within the next four to five years, funded in part through domestic sources.

Where US dollar/Euro denominated financing is the only possibility, the use of a foreign exchange liquidity facility may be one solution, as it requires the PPA to be indexed to the local currency inflation, rather than the foreign exchange rate, and hence power prices will not go up faster than domestic inflation.³¹⁶ In terms of the sample, however, the most wide-spread and effective practice witnessed to date is the indexation of payments to a basket of currencies, as seen in Morocco's Jorf Lasfar, CED and Tunisia's Rades II project, highlighted in section 3.4.1.

³¹⁴ Egypt's Sidi Krir plant did obtain local currency financing, however, it was US dollar denominated and therefore this ultimately did not help assuage the effects of the currency devaluation for the host country.

³¹⁵ Morocco and Tunisia saw minimal fluctuation, and Nigeria's fluctuations were limited to the period before 1998, when the first IPP was negotiated. Cote d'Ivoire experienced a major currency devaluation in 1994, however, this predated the IPPs, and was prompted by a World Bank and IMF proposal rather than an exogenous macroeconomic shock.

³¹⁶ There has, however, only been one such application to date, namely the AES Tiete project in Brazil. A standby credit facility of US\$30 million was used to mitigate devaluation risk and closed in May 2001 (Matsukawa, Sheppard et al. 2003:19)

7.4.3 Securing revenue: The PPA and other security arrangements

All of the projects evaluated had a long-term power purchase agreement with the (majority) state-owned utility³¹⁷ to ensure a market for the power produced (with the exception of Mtwara).³¹⁸ Such a contract was demanded by equity and debt holders alike given the lack of liquid markets for electricity in the sample of countries—a practice which held true across the larger Stanford PESD IPP study as well. As a result, in most cases there was competition for the market, but no actual competition within the market once the PPAs were negotiated, with contracts averaging approximately twenty years.

In addition to indicating who would buy the power, the PPAs detailed how much power would be bought and at what cost. How plants would be dispatched, fuel metering, interconnection, insurance, *force majeure*, transfer, termination, change of law provisions, refinancing arrangements, dispute resolution were generally all clearly laid out as well. Nearly all of the contracts specified some form of international dispute resolution and all but one contract specified a minimum availability, with Tunisia's SEEB being the exception.

These contracts were in turn backed by a series of security arrangements, including in some cases escrow accounts, letters of credit, stand-by debt facilities, committed public budget and/or taxes/levies, targeted subsidies and indexation in contracts. For instance, the Tsavo plant in Kenya, in which IPS is a major shareholder, has an escrow account equivalent to one month's capacity charge and a stand-by letter of credit from KPLC, which covers three months billing of approximately US\$12 million. It is known that a minimum of eight of the twenty projects had either an escrow account or a liquidity facility or both, with typical terms being between one and four months capacity charge in reserve (with one month most typical for North African countries and up to four months seen in Tanzania).³¹⁹

Not surprisingly, the number of security arrangements and credit enhancements appears to diminish as risk profiles improve, however there are noticeable exceptions such as the first

³¹⁷ Section 7.3.2 reviews the exceptions, namely Kenya and Nigeria.

³¹⁸ Mtwara currently operates under a two year interim PPA, which is expected will be replaced by a 20 year PPA, to be finalized in 2007.

³¹⁹ As detailed in Appendix A, Morocco's Jorf Lasfar has an escrow account equivalent to one month's capacity charge and Tahaddart has a letter of credit equivalent to one month's payment (which also serves as a form of a liquidity facility). Tunisia's Rades II has an escrow account, however, the amount is not publicly available. The security arrangement for Kenya's Tsavo plant is detailed above in the text, and OrPower4 has since been granted a similar security package. It was specified that Tanzania's IPTL would have an escrow account equivalent to between 2 to 4 months of capacity charge, but this account has not been established. Songas was granted an escrow account for the first 115 MW, with the Government of Tanzania to match every US\$1 spent by the project company. No escrow account was required for the Songas expansion; furthermore the escrow account was used in part to help buy down the AFUDC. The project also negotiated a liquidity facility equivalent to four month's capacity charge for the first three years, declining to two months starting in year four through the remaining years of the contract. To support its interim PPA, Mtwara has an escrow account (amount unpublished), which will be replaced by a form of liquidity facility, termed the Tariff Equalization Facility, once the 20 year PPA takes effect. Cote d'Ivoire's Azito plant has an escrow account equivalent to one month's capacity charge.

wave of plants in Kenya (Westmont and Ibrafrica), where the risk appears to be entirely reflected in the (higher) capacity payments negotiated, however corruption was also alleged in both of these plants.³²⁰ Thus, the 'security arrangement' may lie not in a formal escrow account, but in an informal agreement among sponsors.

In all but one case, sponsors negotiated or were granted outright US dollar or Euro denominated PPAs, thereby reducing project sponsors' exposure to currency devaluation, which in certain cases such as Egypt's devaluation was severe. This may in fact be considered among the greatest security for sponsors and one that ultimately has influenced countries to change their position about further IPP investments. The one exception is in Morocco's final IPP, Tahaddart, which as discussed above was an entirely domestically financed plant, and which therefore had a Moroccan dinar denominated payment stream.

How then did the PPAs and security arrangements fare over time? As discussed at the outset of this Chapter, eight of the projects, nearly half, have faced some form of change to their contract. Thus, many have not proven iron clad as first mentioned in section 2.6.1. Although there does not appear to be a strong pattern between security arrangements and contract changes (meaning that projects with either more or less security arrangements have been more or less susceptible to change), there is evidence for contract changes being directly related to the terms of the PPA in six projects.

Costs in Kenya's first wave of IPPs were inflated in part due to the short duration of contracts (of only seven years). With Ibrafrica facing ongoing pressure to reduce its tariff coupled with an interest in negotiating a second contract, the sponsor voluntarily reduced its capacity charge, enshrined in the PPA, which meant that it did not amortize the full cost of the project over the first contract. At 15 years, Ibrafrica's subsequent PPA is notably longer than its first (and with negotiations presided over by the ERB, tariffs have been deemed significantly cheaper). The oft-referenced Westmont did not negotiate a second contract after it failed to obtain the same terms, namely capacity charges, spelled out in its first PPA. The changes in Kenya's OrPower4 and Tanzania's Songas have also been related in part to the final amount of the capacity charge (as originally spelled out in the PPA).³²¹ In terms of Nigeria's AES Barge, initially sponsored by Enron, the renegotiation of 1999-2000 brought about several changes to the PPA, including a change in the fuel specifications (from liquid fuel to natural gas), which led to a major reduction in the fuel charge for the off-taker. The present renegotiations with AES Barge involve among other things reconsideration of the availability deficiency payment. Under the existing PPA, liquidated damages recoverable for a shortfall in availability are only 30 per cent of the agreed unit cost and payable only at the end of the year.

³²⁰ In 2005 it was found that the then Managing Director of KPLC, Samuel Gichuru, received US\$2 million from Westmont.

³²¹ It is, however, worth reiterating in this context that failure to agree on both the security package and the capacity charge contributed to delays in the development of OrPower4's additional 36 MW.

The current proposal tabled is to increase this per cent significantly as well as ensure that payments are made on a monthly basis. In each of the five cases reviewed here, it has been the original terms of the PPA that have in hindsight been viewed as unsustainable for the host country and hence challenged. The case of Tanzania's IPTL is slightly different. Although the contract was considered unsustainable due to the added capacity of Songas, the IPTL arbitration was prompted by what was deemed a breach in the PPA, namely the project sponsors' substitution of medium speed engines for slow speed engines, without passing on the capital cost-savings to the utility, as per the PPA.

Thus, the PPA has been a central document, however, not necessarily because it has been bombproof. Rather, it has been the focal point of many of the discussions when deals have been considered out of balance.

7.4.4 Credit enhancements and other measures

Of the many different credit enhancements and other risk management and mitigation measures, it is the provision for international arbitration and sovereign guarantees that have been most commonly employed. All projects in the pool specified some form of international arbitration. Sovereign guarantees were extended for seven of the 20 projects in the pool: all three of the Egyptian IPPs, Morocco's Jorf Lasfar, Tanzania's IPTL, Nigeria's AES Barge and Cote d'Ivoire's Azito and Ghana's Takoradi II. However, one of the projects without guarantees (Rades II in Tunisia) was given added assurances by the government. Furthermore, in the case of the Okpai plant in Nigeria, security in the form of the state-owned oil company's revenues were extended. Thus, if the off-taker defaults, NNPC, among the most liquid firms in the country, is liable.

World Bank partial risk guarantees are seen in two of the projects: Jorf Lasfar and Azito. In the case of Jorf Lasfar, the partial risk guarantee protects the commercial lenders should the off-taker and the government fail to make specified termination payments. In the case of Azito, a PRG ensures that commercial lenders will be paid, even if the utility and state default on payments (of both interest and principal) (World Bank 1997; World Bank 1999). In both cases, it is only after there is a breach in the sovereign guarantee that the PRG is triggered (Sinclair 2007:36).³²²

In addition, other measures were engaged. AES Barge has political risk insurance provided by OPIC. OrPower4 has a MIGA guarantee. Jorf Lasfar has a political risk guarantees from the World Bank, the Italian Export Credit Agency and the Swiss Export Guarantee

³²² Among the more well documented World Bank partial risk guarantees has been one extended for Uganda's electricity distribution concession with Globeleq. Here, regulatory risk related to changes in exchange rates, namely the risk that the regulator will arbitrarily interfere in foreign exchange-tariff adjustments, has been mitigated through the use of partial risk guarantees (Globeleq 2006:21; Eberhard 2007:1).

Agency. Despite the multitude of risks perceived, however, and the plenitude of risk insurances available, it is here that the list ends, with no cover for the majority of projects.

What then is the relationship between such credit enhancements and the sustainability of projects? To what extent have they been effective at attracting and/or assuaging lenders? And to what degree have such mechanisms helped keep projects intact or led to a swift resolution, in the face of external pressures?

For each of the Egyptian IPPs, sponsors have indicated that the sovereign guarantees were essential to the deal, given the novelty and size of the projects. There is also evidence for Azito's partial risk guarantee as being among the key's to attract commercial lending (World Bank 1999). The lack of sovereign guarantees has also been cited as the main obstacle for developing the second phase of Ghana's Takoradi II. In Kenya, the only country in the SSA pool not to extend any sovereign guarantees, stakeholders in Tsavo indicated that without such a guarantee, the presence of IFC became critical, both to help arrange debt and share in equity. Across the board, sponsors of the Kenyan projects as well as KPLC cite the absence of sovereign guarantees as hampering the ability to raise private finance. ERB's rejoinder to this charge is that IPPs have been introduced to help commercialize the sector; government guarantees work against this goal, and MIGA and other risk insurers are available to provide such cover.

Finally, in no projects have the sovereign guarantees, PRI or PRGs been invoked, including in those projects which ultimately have faced a change in the contract (namely AES Barge, IPTL, OrPower or Takoradi II). Recourse to international arbitration has only been made in the case of IPTL, with the arbitration serving to shave US\$30 million off of the investment cost. In addition, there is evidence, as described in Chapter five, that a MIGA delegation was sent to ascertain facts in the case of Kenya when OrPower4 was pressured by both the government and KPLC to reduce its tariff, but the guarantee was never officially invoked. Although pressure from KPLC continued thereafter, pressure from the government subsided (after the MIGA visit).

7.4.5 Positive technical performance

Virtually all IPPs in the sample have been characterized by positive technical performance, with exceptions noted in the case of Tunisia's SEEB and Nigeria's plants due to fuel supply (section 7.3.5). IPPs performance is generally superior to state-owned plants, with the example of Kenya highlighted here as an illustration. In terms of availability, between 2004 and 2006, IPPs had an average availability of approximately 95 per cent versus KenGen's thermal plants, which averaged 60 per cent.

Positive technical performance has been instrumental in changing the way IPPs are perceived. Consider for example IPTL, which performed optimally throughout the recent

drought and helped Tanzania to stave off load shedding until 2006. The plant has since been termed “a saviour”, even by stakeholders who indicate that corruption was likely. At the same time, an unexpected break in Songas’ power in 2006, amidst the drought, temporarily tarnished the projects reputation, despite the fact that the plant still reached its average availability as specified in the PPA and all costs were borne by Songas. During its ownership of Port Said and Suez, EDF noted that its management of technological risk, namely by not outsourcing to any firms and handling all contracts within the fully integrated EDF, was also a key factor in leading to relatively positive outcomes for the firm (EDF 2005).

7.4.6 Strategic management and relationship building

Once twenty year contracts are in place, it would seem that the deal is set and the revenue secured, with clear provisions to ensure debt repayment and reward equity. There are, however, several other interrelated actions that deserve mention here. One involves relationship building, including via local partners (as previously discussed) and community social policies adopted by sponsors. Yet another action relates to how sponsors handle the onset of stresses, including through capacity charges and refinancing.

In terms of social policies, numerous project sponsors have adopted outreach programmes to improve relations with local communities. For instance in Kenya, Tsavo power set up a US\$1 million community development fund for the duration of the 20 year PPA, from which grants of US\$50,000 each are disbursed each year to benefit environmental and social activities in Kenya’s Coast Region. Iberafrica has a social responsibility programme, and IPTL also is an active donor to its immediate community. Jorf Lasfar received the American Chamber of Commerce award for community development and developed an ash disposal facility (previously ash was pumped into the sea). CMS’s social responsibility involvement in Ghana included providing scholarships for secondary and tertiary education as well as providing support for both medical clinics and the construction of drainage systems. Although the sums are not significant, these programmes, particularly when well advertised, have the potential to win allies and counter the stereotype of IPPs.

Another perhaps more significant action is how sponsors cope with stress, such as macroeconomic shock and associated currency devaluation or pressure from host governments who perceive costs to be too high. Although anecdotal, there is evidence for how such strategic management aided the Egyptian plants, which may be judged among the most successful in this pool of IPPs. There is also evidence for how strategic management helped put Kenya’s Iberafrica back on track, in contrast to Westmont, where no such management is in evidence. Finally, both of Tanzania’s IPPs may accredit future sustainability in part to such an element.

In the case of the Egyptian devaluation, EEHC appears to have approached Sidi Krir management when the country was experiencing an acute scarcity of dollars to request

payment in pounds to the maximum extent feasible, but that due to its US dollar denominated debt the firm was unable to acquiesce. Minor changes, since the devaluation, are limited to partial payment of the local operating and maintenance component (both fixed and variable) in local currency, which amounts to approximately 4 per cent of the total charge. With Sidi Krir, the change is an informal agreement between the project's general manager and EEHC. With Port Said and Suez, the agreement has gone through negotiations with IFC, but EDF could have chosen to return to US dollar payments at any time, i.e. it was not contractually bound. Although small, these actions do send the message that sponsors are willing to work where possible to make the situation less onerous for the host country.

Kenya's Iberafrica has dealt with two stresses: drought and alleged corruption. It is important to reiterate in this context that the project was also up for a contract renewal at the time when the following actions described were undertaken. According to stakeholders at Iberafrica, the IPP voluntarily lowered its capacity charge at a time when KPLC was operating in the red, due in part to a drought-related recession, to show its support for the country and signal its interest in a second contract (the first lasted seven years). Iberafrica later secured a second contract, albeit after even further reductions were negotiated and passed by the electricity regulator.³²³

A final area which may yield greater balancing in terms of development and investment outcomes is in the refinancing of projects, evidence for which one may see as Songas seeks to refinance its 100 per cent equity investment in the second phase of the plant. Possible refinancing in the case of IPTL with the Government of Tanzania proposing to buy the outstanding debt, and possibly equity, could also lead to what may be perceived as more balanced outcomes. If and when the Government of Tanzania buys back IPTL, it will make a once-off payment on behalf of the utility and then pass the asset ownership to TANESCO, which may subsequently decide to convert the plant to run on natural gas. Through this transaction, the capacity charge will be reduced to a token amount, and following gas conversion, the energy charge dropped from US\$9-12 million to US\$1-1.5 million per month. The PPA will be terminated, a new agreement drafted, and the customers will see discounted tariffs.

Refinancing does, however, only have limited application, and must be dealt with carefully during the project negotiation for as one banker candidly indicated: "if project finance bankers are expected to finance projects with the understanding that periodically it will be necessary to have a restructuring, the outcome of which is uncertain, the result will be to

³²³ It should, however, be noted that the fact that Iberafrica was not project-financed meant that the company was at greater liberty to change the payment streams.

eliminate the availability of non-recourse financing”—which, given the already low levels in Africa should be avoided.³²⁴

It is the government’s willingness to share risks over the life of the project, which may also be pivotal in the long-term sustainability of projects. Strategic management does not occur in a vacuum, with the sponsor alone. Often the host country government may not only be an active counterparty, but even, as evidenced in the refinancing of IPTL, initiate such strategic management. Other government led initiatives include, among others, Morocco’s ONE assuming a greater equity share in Tahaddart when EDF pulled out and the Government of Tanzania’s buying down of Songas’ AFUDC.

In sum, how may one understand the limited but still revealing sample of IPPs analyzed by this thesis? There are two natural fault lines. The first cuts between North Africa and Sub-Saharan Africa, and the second, between those projects in SSA that faced some form of contract change and those that did not.

The main difference between IPPs in North Africa and those in SSA is that the former took root in significantly more attractive investment environments than the latter. In turn, competition was greater, as were ICBs, which may have also contributed to cost reductions. Also of significance in most of the North African projects is that despite exogenous stresses, policy frameworks remained largely intact and planning mishaps were fewer than in the SSA sample. Most North African IPPs benefited from abundant low cost fuel and secure fuel contracts as well as credit enhancements such as sovereign guarantees. For the most part, with few exceptions, these contributing elements to success were absent in SSA. Certain SSA projects did in fact benefit from ICBs, as well as abundant fuel resources and credit enhancements, but generally speaking, the abovementioned elements were largely consistent across the North African pool.

Although distinguished by relatively less attractive investment climates, the SSA IPP sample is not homogenous. What if any are the shared characteristics among the seven projects (Iberafrica, OrPower4, IPTL, Songas, Takoradi II, AES Barge and Okpai), eight if Westmont is included, that underwent some form of contract change? Furthermore, does the balance of SSA IPPs that did not see any form of change (Tsavo, Mtwara, CIPREL and Azito) exhibit any common elements?

The IPPs that have seen changes to their original contracts were all procured amidst a form of electricity crisis, mostly as a result of drought in largely hydro-dependent systems. Furthermore, often World Bank sanctioned power master plans and/or conditional loans were passed over to plug the immediate power crisis. In such crisis situations, ICBs were only

³²⁴ See footnote 309 for indication of low project finance levels in Africa.

followed in two of the eight IPPs; furthermore, in the two projects that did see an ICB (Songas and OrPower4) only two bids were received. Such crisis conditions did not predominate to the same degree in the group of IPPs that have not seen changes. Although ICBs were still limited (Azito and Tsavo), it is arguable that the IPP framework was more clearly defined, bidding was more transparent and ultimately more thorough due to the fact that plants were procured under less urgent circumstances than in the group of eight discussed above.

Furthermore, there is a discrepancy in the prominence of DFIs and/or development-minded firms in the two different groups of SSA IPPs evaluated by this thesis. In all four of the projects that have stayed intact to date in SSA, multilateral and bilateral development institutions and/or development-minded firms have been equity holders (IPS and IFC in Tsavo, FMO in Mtwara, IFC in CIPREL, and Globeleq and IPS in Azito). In addition, most of these projects have also benefited from concessionary funding, provided and/or arranged by DFIs. In contrast, in the eight remaining projects, which have encountered some form of change, such agencies and firms have been notably less present on both the equity and debt side. Only one of the eight projects had a development minded firm as an equity holder (Globeleq in Songas).³²⁵ Only one of the eight projects saw involvement of a DFI on the debt side (World Bank in Songas).³²⁶ Finally, it is important to reiterate here that Songas' contract changes were linked to the delays caused by the negotiation and ultimately arbitration of IPTL.

The two elements described above, namely the electricity crisis and the prominence of DFIs and/or development-minded firms are (like the favourable investment climate of North Africa) by far the most far-reaching elements in terms of differentiating the two groups of SSA IPPs evaluated here. There are, however, a couple additional elements that help explain some of the variation in the two groups. The absence of abundant low cost fuel also characterizes five of the eight projects that saw changes (Westmont, Iberafrica, IPTL, Takoradi and AES Barge), with only one project in the group of four (Tsavo) that have not seen changes not benefiting from abundant low cost fuel. Also worth mentioning is the fact that four of the eight ended up funding projects entirely with their balance sheets (Westmont, Iberafrica, OrPower4, and Okpai). Interestingly, although PPAs, credit enhancements, security arrangements, positive technical performance and strategic management have all emerged to shape particular projects, there is no fully conclusive data across the pool. Also noteworthy is the fact that of the four projects that have seen no changes, there were no local partners, including no participation on behalf of the government. In contrast, of the eight that did see a change, local partners, including government were present in six of the projects.

³²⁵ However, Globeleq only came into Songas, after the AFUDC had accumulated and is credited in part with allowing the buying down of the AFUDC by the government.

³²⁶ Furthermore, OrPower4 did obtain a MIGA guarantee.

including technological selection, joint ventures with local partners, as well as a suite of new protections (including political risk insurance and partial risk guarantees) and international arbitration also emerged to help protect foreign investors and their investments from outright or creeping expropriation.

What then did the review of three in-depth country case studies and five additional country narratives reveal about the obsolescing bargain and the new protections as well as their relationship to the balancing of development and investment outcomes?

7.6.1 Setting of the initial bargain and risk management measures

As discussed throughout, the investment conditions (and perceived investment risks) between the North African and Sub-Saharan Africa examples are markedly different. According to the theory of the obsolescing bargain, detailed above, one would expect to see a corresponding difference in the relative power between stakeholders at the initial contract negotiation, which in turn should affect the terms of the deal and security measures engaged. Thus, investors in SSA should, according to obsolescing bargain theory, attempt to tilt outcomes their way at the outset, due to the perception of higher risks, and obtain more safeguards for such arrangements. Likewise, it would be expected that there would subsequently be a greater effort by host countries to rebalance projects, in their eyes, or even expropriate value (as will be assessed in the next section).

There are signs that investors in some of the first SSA IPPs (namely, Kenya's Westmont and Iberafrica, Tanzania's IPTL and Nigeria's AES Barge) indeed sought to tilt outcomes in their favour, with higher risk premia demanded at the outset, and in most cases debt amortized within the first few years of the contract. Little evidence appears to point to such actions in the North African sample. In this respect, investor behaviour does appear to conform with the obsolescing bargain theory. In each of the more risky cases, agreements were safeguarded via long-term PPAs, however, this has also been observed across the entire pool, with the one exception of Tanzania's Mtwara plant. In addition, all projects have specified recourse to international arbitration should a dispute arise and not be able to be resolved in local courts. Thus, neither the PPA alone nor the provision for arbitration is unique to the more risky cases. As regards other safeguards, about half of North African projects had government guarantees (Egypt's three IPPs and Morocco's Jorf Lasfar). Surprisingly, however, less than half of the Sub-Saharan plants had such guarantees (only Cote d'Ivoire's Azito, Ghana's Takoradi, Nigeria's AES Barge and Tanzania's IPTL). Furthermore, contrary to the prediction that a more risky investment environment would mean more investment safeguards, only two of the Sub-Saharan pool of 11 projects had any form of political risk insurance (MIGA for OrPower4 and OPIC for AES Barge). Although this is greater than the North African pool, where only Jorf Lasfar is reported to have PRI, the scarcity of such insurance in the relatively more risky

Sub-Saharan African pool is noteworthy. In addition, only two projects in the sample benefited from partial risk guarantees (Jorf Lasfar and Azito), both provided by the World Bank.

In reviewing the North African cases, one World Bank official, heavily involved in the sector indicated, “Egypt, Tunisia, and Morocco are acceptable risks so do not need credit enhancements, although we did provide a PRG for Jorf Lasfar, [due to the size and the scope of the project].” This comment sheds light on the paucity of such credit enhancements for North Africa, but it does not explain the absence in SSA. Development finance institutions did, however, take an active role in both equity and debt, which may, in some respects, have served as a form of credit enhancement. Yet again, though, the numbers do not fit precisely with the obsolescing bargain theory: six out of the twelve SSA projects recorded involvement of a DFI in contrast to five out of the eight North African projects. That is, such involvement was relatively higher in the less risky North.

The data does, however, conform to the prediction with regard to local joint venture partnerships, as the majority of Sub-Saharan projects engaged some form of local partner (in contrast to just one project in North Africa that did so, namely Morocco’s Tahaddart). Another example, as noted previously, is that escrow accounts in the North African sample appear to be of shorter duration than those in the Sub-Saharan sample.

Thus, while the possibility of the obsolescing bargain theory does appear to help explain some of the investor behaviours adopted, including the higher premia, security arrangements and joint ventures, there is also a divergence between theory and practice, which points to the possibility that firms did not take such a threat seriously, believing instead that the original deals would endure.

7.6.2 Evidence for the bargains obsolescing

Did projects face pressure over time from host governments to renegotiate? If so, did the iron clad PPAs, the security arrangements and credit enhancements fend off the obsolescing bargain? As reviewed at the beginning of this Chapter, the complete unravelling of contracts has been almost nil, with the special cases of SIIF Accra and Osagyefo Barge being the two exceptions. One might therefore conclude that the theory of the obsolescing bargain did not apply. On closer inspection, however, there is significant evidence for sponsors being pressured to renegotiate contracts as well as several notable changes to contracts. Eight of the 20 projects have faced a change in their contract (Tunisia’s SEEB, Kenya’s Ibrafrica and OrPower4, Tanzania’s IPTL and Songas, Ghana’s Takoradi II and both of the Nigerian plants, AES Barge and Okpai). Furthermore, one additional IPP has been pressured to do so, but ultimately resisted (Kenya’s Tsavo), and Kenya’s Westmont was pressured in the negotiation of a second contract to do so, and ultimately decided to withdraw. Thus, about 50 per cent of the sample is known to have faced pressure, with the majority in SSA.

Following the prediction of the theory, the obsolescing bargain unfolded primarily in those cases where outcomes were later perceived by public stakeholders to be tilted toward investors, at the expense of the country, i.e. where there was the growing perception of an imbalance. As reported in Wells and Ahmed, “ultimately, security for most investors lies in how a particular project is perceived by its hosts—by government officials, but also in a democratic Third World, by the press, labour, and nongovernmental organizations” (2007:298).

Thus, there are almost no examples in the North African sample, and the examples in the SSA may be identified with certain types of projects where the gap was seen to be relatively greater. In each case, with the exception of Okpai, for which the renegotiation is ongoing, tariffs have come down from what was originally agreed upon. Post-renegotiation, however, although in most cases, pressure has continued from the host country government, there have been limited additional contract changes, with the one exception that of AES Barge where the firms has seen a withholding of the tax exemption certificate; that is, there is no evidence for outright expropriation and creeping expropriation may only be noted in one case. In sum, new agreements are reached, and generally, operations continue.

7.6.3 A case for the new protections or for balancing outcomes?

Do the numerous examples of contract changes that occurred with SSA IPPs in turn signal that the obsolescing bargain is applicable, and that the standard risk strategies adopted by partners were insufficient? Alternatively, might there be another answer to this question that does not fit within either Vernon’s original thesis or those who built on it including Wells, as described in section 2.6.1?

Although security arrangements and credit enhancements, as described above, were in existence, they were not as plentiful as one would expect. Furthermore, many of the projects that did see some form of their contract renegotiated had such protections: OPIC political risk insurance and sovereign guarantee for AES Barge, sovereign guarantee for IPTL and a joint venture with a local partner, and MIGA for OrPower4. Thus, perhaps one could speculate that such arrangements helped prevent further unravelling from happening, but the data is inconclusive in pointing to the pivotal role of such protections in keep the obsolescing bargain at bay.

In sum, on the one hand, where there was a perceived balance between sponsors and host country governments, contracts generally remained intact, as seen in most of the North African cases, with the balance largely accredited to the more favourable country level factors (such as favourable investment climates, clear policy frameworks, and ICBs, among others). On the other hand, perceived imbalances (often exaggerated by exogenous stresses) between sponsors and host country governments frequently did lead to an obsolescence of the original contract.

Contrary to expectation, the series of protections described above were not *the* determining factor in outcomes.³²⁷

Although the evidence is not conclusive, strategic management on behalf of sponsors and government as well as strong technical performance have been used to cope with the obsolescing bargain. Furthermore, the fact that projects with participation of development-minded firms and DFIs were less likely to feel the effects of the obsolescing bargain signals two points: such projects may have been more balanced from the get-go, and when an exogenous stress struck, they may have also been better equipped to resist the obsolescing bargain.

Thus, the findings are four-fold. First, evidence for the obsolescing bargain is widespread across the pool of African IPPs where an imbalance is perceived, which largely corresponds to the more risky SSA projects. Focusing on identifying the key variables to explain project outcomes across the pool of 34 projects, the Stanford PESD IPP study passed over the obsolescing bargain as holding significant explanatory power. This thesis would, however, argue that the theory does explain more about investor behaviour, which has an inevitable impact on outcomes, than PESD reported.

Secondly, the incidence of the obsolescing bargain does not signal the end of a project's operation. New agreements may be reached, albeit at a cost, that prove sustainable. Third, efforts must continue to close the initial gap between investors and host country governments (or else examples of the obsolescing bargain will continue), as Vernon himself argued at the end of *Sovereignty at Bay* (1971). Finally, the means to closing the gap may not necessarily be via increasing the sort of new protections, including political risk insurance, which have been reported to often confound political and economic issues (Moran 2006:80-81) and may instead lie in the numerous contributing elements to success defined by this thesis.

7.7 Power sector reform framework

7.7.1 The reform agenda emerges

IPP investments were made within the context of a broader reform programme, which sought to address the poor technical and financial performance that persisted in many developing countries. At the heart of the programme was the idea that the private sector could procure, operate, and often own electricity assets more efficiently than the public sector. This fundamental shift—from state to market—reversed decades of state-led development and

³²⁷ The protections do, however, hold some explanatory power, as seen for instance in the case of OrPower4. Following the visit paid by the MIGA delegation, pressure from the Government of Kenya on the firm reduced (although pressure from KPLC continued and ultimately led to a renegotiation of tariffs).

operation, which had become the accepted truth for most ESIs (and other infrastructure industries) globally in the post World War II years.

Electricity sector reforms were pioneered in the USA, UK, Chile and Norway, countries that were known for their relatively high access rates (including Chile). In addition, a number of these early reformers had excess supply capacity, conditions that differed drastically from the majority of developing countries, which would later be the subject of reform.

Despite differences in starting conditions, gradually the reform crystallized into a standard model, which specified the need for corporatization and commercialization of the state utility, followed by passage of legislation, establishment of an independent regulator, the introduction of IPPs, restructuring, divestiture of state assets and the introduction of competition.

Caution over the enactment of such a model was urged. As highlighted in section 2.4.4, the inapplicability of one-size-fits-all solution has long been acknowledged, at least in print. In Bacon (1995a:32-33), not only was possible exemption made for small systems, but the reform approach was one based on questions (not answers) as presented in his conclusion. To take the example of IPPs, according to Bacon, the order was not, introduce IPPs, but rather “What will be the gains, in terms of the price of entry of IPPs, from separating transmission from generation? Over what period will the IPPs enter, with what capacity, and what price advantages will be gained in comparing the bids into a separated system as opposed as into an integrated system?”

The thinking espoused by Bacon in 1995 as well as other voices of reason did not, however, filter into practice, in all instances. Instead, a standard prescription, with a specific end state, has been the main message spread by DFIs, international consultants (involved in the early reforms particularly in the UK and Latin America), as well as domestic champions of the reform model over the past 15 years. This model has been promoted, despite the fact that it was never made official policy by DFIs, most notably the World Bank.

7.7.2 Enacting the reform agenda

In each of the countries evaluated in this thesis, as well as many other countries across Africa and other developing regions, power sector reform, a la standard model, has been undertaken. Despite these efforts, in no country in Africa (and virtually none in other developing regions) has the end state of the standard model been realized.

That is not to say that pieces of the model are not in evidence. Over the course of the past two decades, ESIs have adopted greater commercialization practices, and steps have been taken toward corporatization. There is evidence for the passage of energy laws providing for third party access; new regulatory organizations abound. Numerous countries, as documented by this thesis, have also adopted IPPs. It is here, however, where the steps of the standard model stop, with little achieved in terms of full unbundling (vertical as well as horizontal), privatization of

the ESI, and the introduction of wholesale and retail competition. Furthermore, it should be noted that the sequencing of the steps that have been undertaken, has not always been per the original model. For instance, in many countries, regulators came into existence only after the first IPP contracts were negotiated. Commercialization efforts have often only picked up post-IPPs as well.

Not only have the steps been out of order, but the actual motivating forces have also differed from what was conceived in the standard model. For instance, the rationale for IPPs, according to the model, was that the introduction of privately financed and often privately owned generation would help the sector move toward greater efficiency by providing a benchmark to state-owned plants. Further advantages cited were that IPPs would introduce competition for the market (yielding lower tariffs), which was also considered a step toward competition in the market.

In practice, however, IPPs have been adopted in numerous countries in this thesis' sample at a time when there were no public funds available and often an electricity supply crisis prevailed. Thus, the situation was often one of emergency, with the need for urgent power the impetus, rather than long-term efficiency of the ESI. Decisions taken in such crisis situations have frequently locked countries into 20 year commitments, with widespread evidence for renegotiations in such instances, as the original terms are deemed obsolete.

It is perhaps valuable to briefly consider what has happened in African countries that have experimented with the standard model, but have not developed IPPs. How have they fared, and are they any closer to or further from the end state of the standard model? Malawi, Mozambique, Zambia and Zimbabwe have also sought to unbundle, privatize and introduce competition, but did not attract any IPPs. In each case, however, the countries also stopped in the reform path, long before unbundling and competition were completed.³²⁸ Thus, the presence or absence of IPPs does not appear to explain the lack of progress in achieving the standard model to date.

7.7.3 Mid-way or a new path?

What does the fact that no African country has adopted the standard model full cloth, despite the intense pressure to reform ESIs as outlined in Chapter 2, say about the model? Is the road simply longer than anticipated and the standard model still applicable, or has a new model come into play?

Although IPPs may slow the process, particularly when associated with alleged corruption, as described in Chapter six in the context of IPTL, they are not impediments to the

³²⁸ A number of authors chart the reforms of one or more such countries: Zimbabwe (Dube 2000:121-151); Malawi, Mozambique, Zambia Zimbabwe (SAD-ELEC 2004:24,27,51,55); Malawi, Zambia and Zimbabwe (United Nations Environment Programme and United Nations Economic Commission for Africa 2006).

enactment of the standard model, particularly if they are procured in a transparent manner and are part of a country's power system master plan. The means to integrating IPPs into wholesale competition are many and may include: forced market integration by enacting legislation; integration through a change in market rules; forced renegotiation; financially facilitated market integration, contract buy-out and facilitated voluntary renegotiation or buy-out (Woolf and Halpern 2001:13).

Despite such a wide range of alternatives for moving from IPPs to wholesale competition, there is little evidence, for such movement. Instead, largely state-owned utilities are maintaining significant (often dominant) market share. New publicly funded plants are being built, often with support of concessionary loans. A hybrid market is emerging where long-term take or pay contracts with IPPs exist alongside publicly owned and operated plants. Might this signal then not a mid point in the standard model but rather a new model altogether?³²⁹

If a new model is indeed emerging, which the evidence would suggest, then it is time to acknowledge that the standard model, which has been the organizing principal for power sector reform over the last decade and a half, serves neither a descriptive nor a prescriptive role. Simply stated, the death of the standard model must be broadcast.³³⁰ Instead, a tailor-made solution as recently acknowledged again by Besant-Jones is in order, given the range of economic and political/institutional conditions that predominate (2006:1).

Within such tailor-made solutions, serious attention should be paid to policy and planning frameworks and the institutions that will carry out such work. Clear policy frameworks, signalled throughout this thesis in the context of evaluating contributing elements to success for IPP projects, must be enshrined in legislation, and specify the market structure (generally a single buyer) and the roles and terms for private and public sector investments alike. Before coherent power sector planning is undertaken, decisions about where to site such planning must also be taken. In a hybrid market, should planning still be undertaken by the state-owned utility, or should an alternative be found, vesting planning in an independent government

³²⁹ Although a discussion of why the standard model may not have been realized in the country cases above is beyond the scope of this thesis, two points are worth noting in this context. A country's commitment has often been cited as the key (missing) ingredient (World Bank 1993a:72; Bacon and Besant-Jones 2002:4; Besant-Jones 2006:2-3; Woodhouse 2006c:22). In their recent work, Victory and Heller posit that the answer to this question may run deeper than mere political will/commitment and relate to investment crises predominating in countries at the inception of reforms as well as the lack of financial and judicial reforms undertaken by a country (2007:256,259).

³³⁰ Numerous authors have challenged the applicability of the standard model, describing how a mismatch between the conditions that predominated in those countries where power sector reform was initiated and most developing countries, has led to negative outcomes (Wamukonya 2003:1285; Williams and Ghanadan 2006:836; Yi-chong 2006:821). Proponents of the model are, however, still numerous, and as indicated previously plans to enact the model are still be considered in among other countries Tanzania (Joskow 2006:7-8,14; Mercados per com 2007; Parastatal Sector Reform Commission per com 2007). Such criticism is slowly beginning to make its way into the mainstream as seen through the recently published World Bank treatise *Reforming Power Markets in Developing Countries: What Have We Learned*, cited above (Besant-Jones 2006).

agency, a single buyer office or an independent system operator? In making such a decision, the guiding principle should be what organization is most capable of making independent and fair allocations of new builds and overseeing a transparent bidding process? It may ultimately be decided that additional governance mechanisms must be introduced into the sector to ensure such a fair allocation between private and public players. Although seemingly mundane, unless properly addressed these issues could hamper investment on the continent as private producers perceive that they are competing in an unfair game where the incumbent state-owned utility always has the upper hand, or vice versa. It has been demonstrated that the standard model no longer serves a descriptive or prescriptive role, what now needs to be developed is how to efficiently manage a hybrid market, taking into consideration the wide array of considerations of stakeholder.

This thesis sought to evaluate the experience of IPPs in Africa and explore the relationship between development and investment outcomes. The primary question asked was whether the balancing of such outcomes leads to more sustainable projects. The answer, as illustrated by the experiences of eight different countries in North and Sub-Saharan Africa, is that indeed a balance between outcomes does lead to sustainability; however, such a balance is, given the conditions that predominated at the time that many IPPs were procured, often only achievable over time, including via renegotiation. In elucidating the issue of balancing outcomes, this thesis developed a suite of contributing elements to success and analyzed the interplay between such elements and outcomes. Although each of the elements proved relevant, the most far reaching were: favourable investment climates; clear policy and planning frameworks and favourable equity and debt arrangements, including the participation of a development-minded firm and/or a DFI.

To better understand both the investment and power sector context of African IPPs, the thesis engaged two different sets of literature. The obsolescing bargain theory, within FDI literature, was drawn upon to help understand the original conditions of the deal and their impact. Following the prediction of the obsolescing bargain theory, the African IPPs evaluated here demonstrated that deals perceived to be out of balance, by public stakeholders, were often forced to renegotiate. Although there was no outright expropriation of assets, original deals in nearly half of the projects studied did obsolesce. Furthermore, in most instances, the spate of new protectionisms, including PRI and PRG, did not ward off the obsolescing bargain. The key lay instead in the original conditions of the deal, namely creating more balanced development and investment outcomes, as evidenced by the lack of the obsolescing bargain across the North African IPPs. For those projects that did face renegotiation, DFI involvement, rather than PRI, proved significant as well as a number of other elements identified by this thesis, including the strategic management of projects.

Although this thesis has attempted to take the understanding of African IPPs forward, including by engaging the obsolescing bargain, the greatest contribution to knowledge of this thesis may be in its analysis of the power sector reform context in which IPPs arose. Through detailed case studies as well as an extensive review of reform literature and interviews with policy makers, this thesis found that the standard model for power sector reform had many authors and proponents, including a band of international consultants involved in some of the earliest reforms in the UK and Latin America; that is, it was not exclusively owned or led by the World Bank. In addition, despite numerous warning signs not to apply the standard model to small systems such as those characteristic of most Sub-Saharan countries, the model was used extensively with little regard to country specifics. Furthermore, such a model although applied, has not actually been realized. Instead, hybrid electricity markets emerge, which include state-owned and privately owned entities and present a series of challenges, as this thesis has illustrated through its review of country cases. Finally, an attempt has been made to outline key elements that may help improve the organization and ultimately the performance of such hybrid markets, without, however, suggesting that any standard approach be adopted.

Appendix A

Detailed specifications are presented for each IPP discussed in this thesis. The organization of the data is as follows. Information is first grouped into regions with North Africa, followed by East Africa and West Africa. Countries within each of the regions are presented in alphabetical order. Under each country, IPPs are then presented in terms of chronological order, based on the date when the IPP first came online, as per the outline below.

Region/Country/Project	Page numbers
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North Africa

Egypt (1 of 3 projects)

Project	Sidi Krir
Size	683 MW
Cost	US\$413.9 million ³³¹
\$ per kW	606
Technology	Natural gas/steam cycle
ICB	Yes
Contract	BOOT, 20 years
Debt/Equity	33/67
DFI in equity and debt	None
Local participation in equity and debt	Yes (equity)
Equity partners (country headquarters & % of each)	InterGen (USA, 60%) & Edison (USA, 40%) sold to Globelec (UK, 100%) in 2004-2005, conditional sale to PEL (JV between Malaysia Tanjong & Saudi Arabia AlJomaih, 100%) in 2007
Lenders	60% sourced from local Egyptian banks, led by Commercial International Bank, with remaining 40% provided by international commercial banks
Credit enhancements	Sovereign guarantee
Security arrangements	None
Project tender, COD	1996, 2002
Contract change	None
Fuel arrangement	Fuel provided by Gasco, national gas company, at sub-economic rates, project sponsors pay Gasco and are subsequently reimbursed by EEHC, i.e. not a direct pass through

³³¹ Previously project costs were estimated at US\$417.8, however, following negotiations with Egyptian customs authorities costs were reduced to US\$413.9.

Egypt (2 & 3 of 3 projects³³²)

Project	Port Said & Suez
Size	683 MW each (for a total of 1366)
Cost	US\$340 million (Port Said) and US\$338 million (Suez)
\$ per Kw	498, 495
Technology	natural gas/steam cycle
ICB	Yes
Contract	BOOT, 20 years
Debt/Equity	25/75
DFI in equity and debt	Yes (debt)
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	EDF (France, 100%) sold to Kuasa Power, subsidiary of Tanjong (Malaysia, 100%) in 2006
Lenders	IFC, Societe Generale, Barclays, and John Hancock (the USA-based insurance firm)
Credit enhancements	Sovereign guarantee
Security arrangements	None
Project tender, COD	1998, 2002 (Port Said) and 1998, 2003 (Suez)
Contract change	None
Fuel arrangement	Fuel provided by Gasco, national gas company, at sub-economic rates, project sponsors pay Gasco and are subsequently reimbursed by EEHC, i.e. not a direct pass through

³³² Port Said and Suez are grouped under one profile as the project size, type and sponsor were identical. The only distinction between the two plants was in the capital cost, with Suez, which was negotiated after Port Said, recording a lower capital cost.

Morocco (1 of 3 projects)

Project	Jorf Lasfar
Size	680+680 ³³³ MW
Cost	US\$1500 million ³³⁴
\$ per kW	US\$1,103
Technology	Coal
ICB	Yes
Contract	BTO, 30 years
Debt/Equity	67/33
DFI in equity and debt	Yes (debt)
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	CMS (USA, 50%) and ABB (Swiss, 50%) sold shares to TAQA (UAE, 100%) in 2007
Lenders	USA ExIm (US\$200 million), OPIC and a syndicate of approximately 50 commercial banks
Credit enhancements	PRG from the Italian Export Credit Agency (SACE), the Swiss Export Risk Guarantee (ERG) and the World Bank
Security arrangements	Escrow account equivalent to 1 month capacity charge
Project tender, COD	1994, 2000
Contract change	None
Fuel arrangement	Coal procured by project, with 80% of coal costs reimbursed at the average cost of coal procured by project and 20% of costs reimbursed at average cost of coal imported into European Union

³³³ The first 680 MW refer to an existing facility, i.e. a brownfield investment; the greenfield investment was an additional 680 MW.

³³⁴ The project costs included the upgrade of the coal receiving facility and also the infrastructure for transporting coal to ONE's Mohamedia plant.

Morocco (2 of 3 projects)

Project	Compagnie Eolienne de Detroit (CED)
Size	50 MW
Cost	\$58.5 million ³²⁵
\$ per kW	\$1,170
Technology	Wind
ICB	Yes
Contract	BTO, 19 years
Debt/Equity	70/30
DFI in equity and debt	Yes (debt)
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	EDF (France, 49%), Paribas (France, 35.5%) & GERMA (France, 15.5%) maintained equity since 1997
Lenders	EIB (€24.4 million), PROPARCO, Credit Agricole (now Calyon) and other commercial banks
Credit enhancements	None
Security arrangements	None
Project tender, COD	1995, 2000
Contract change	None
Fuel arrangement	No energy charge, wind powered

³²⁵ Project costs quoted in Euros at €45.7, converted to US\$ on August 24 2006 at exchange rate of €1=US\$1.28.

Morocco (3 of 3 projects)

Project	Tahaddart
Size	384 MW
Cost	US\$364.9 million
\$ per kW	US\$950
Technology	Natural gas/combined cycle
ICB	Yes
Contract	BTO, 20 years
Debt/Equity	75/25
DFI in equity and debt	None
Local participation in equity and debt	Yes (equity and debt)
Equity partners (country of origin & % of each shareholder)	ONE (Morocco, 48%), Endesa (Spain, 32%) and Siemens (Germany, 20%) maintained equity since 1999
Lenders	Banque Centrale Populaire, Banque Marocaine pour le Commerce Exterieur, Credit Agricole
Credit enhancements	None
Security arrangements	Letter of Credit equivalent to 1 month capacity charge
Project tender, COD	1999, 2005
Contract change	None
Fuel arrangement	Government supplies gas (which is received as a royalty from the Algerian Spain pipeline)

Tunisia (1 of 2 projects)

Project	Rades II
Size	471 MW
Cost	US\$260.7 million
\$ per kW	US\$554
Technology	Natural gas/combined cycle
ICB	Yes
Contract	BOO, 20 years
Debt/Equity	70/30
DFI in equity and debt	Yes (debt)
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	PSEG (USA, 60%) sold shares to BTU Power Company (GCC, 60%) in 2004, Marubeni (Japan, 40%) retained shares since 1999
Lenders	JBIC, BNP Sanwa and other commercial banks
Credit enhancements	No sovereign guarantee but did receive reassurances from government that STEG would be able to meet its obligations; JBIC also received Letter of Comfort from Ministry of Energy indicating government committed to success of project
Security arrangements	Escrow account (amount not publicly available)
Project tender, COD	1997, 2002
Contract change	None
Fuel arrangement	Fuel supplied by STEG and fuel costs are a pass through to STEG

Tunisia (2 of 2 projects)

Project	Societe d'Electricite d'El Biban (SEEB)
Size	27 MW
Cost	US\$30 million ³³⁶
\$ per kW	US\$1,111
Technology	Natural gas/open cycle
ICB	None, but selective international tender conducted
Contract	BOO, 20 years
Debt/Equity	67/33
DFI in equity and debt	None
Local participation in equity and debt	Yes (debt, but US\$ denominated)
Equity partners (country of origin & % of each shareholder)	Centurion (USA, 50%) sold to Candex (Canada, 50%) in 2005, Caterpillar (USA, 50%) maintained equity since 2002
Lenders	ABC International Bank (50%), AMEN Bank (50%)
Credit enhancements	None
Security arrangements	None
Project tender, COD	2000, 2003
Contract change	Project has not been able to secure its fuel supply and is presently offline
Fuel arrangement	Project responsible for providing fuel

³³⁶ Project costs include the gas infrastructure.

East Africa
Kenya (1 of 4 projects)

Project	Westmont
Size	46 MW
Cost	US\$65 million
\$ per kW	US\$435
Technology	Kerosene/gas condensate/gas turbine (barge mounted)
ICB	None, but selective international tender conducted
Contract	BOO, 7 years
Debt/Equity	NA
DFI in equity and debt	None
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	Westmont (Malaysia, 100%) has sought to sell plant since 2004
Lenders	NA
Credit enhancements	None
Security arrangements	None
Project tender, COD	1996, 1997
Contract change	Not a contract change per se, but firm failed to negotiate a second contract after its 7 year contract ended in 2004 due to failure to agree on tariffs
Fuel arrangement	Originally Westmont to procure fuel and then pass through to utility, however, following dispute with fuel supplier about taxes after the first year of operation, utility took over procurement

Kenya (2 of 4 projects)

Project	Iberafrica
Size	56 MW
Cost	US\$35 million
\$ per kW	US\$1,161
Technology	HFO/medium speed diesel engine
ICB	None
Contract	BOO, 7 years + 15 years ³³⁷
Debt/Equity	72/28
DFI in equity and debt	None
Local participation in equity and debt	Yes (equity and debt)
Equity partners (country of origin & % of each shareholder)	Union Fenosa (Spain, 80%), KPLC Pension Fund (Kenya, 20%) since 1997
Lenders	Union Fenosa (US\$12.7 million in direct loans and guaranteed US\$20 million); KPLC Staff Pension Fund (US\$9.4 in direct loans and guaranteed US\$5 million through a local Kenyan bank).
Credit enhancements	None
Security arrangements	None
Project tender, COD	1996, 1997
Contract change	Yes, Iberafrica reduced the capacity charge of its first PPA by 37 per cent in April 2002 and then to 59 per cent of the original PPA in September 2003. ³³⁸
Fuel arrangement	Iberafrica buys fuel and passes cost through to KPLC based on the units generated and specific consumption parameters agreed on in the PPA

³³⁷ Iberafrica has had two different PPAs, the first spanning 7 years, the second, signed in 2004, which will span 15 years.

³³⁸ Furthermore, although not a contract change per se, the value of the capacity charge for Iberafrica's second PPA was 50 per cent that of the first PPA.

Kenya (3 of 4 projects)

Project	OrPower4
Size	13 MW
Cost	US\$54 million
\$ per kW	US\$4,154
Technology	Geothermal
ICB	Yes
Contract	BOO, 20 years
Debt/Equity	NA
DFI in equity and debt	None
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	Ormat (100%) since 1998
Lenders	NA
Credit enhancements	MIGA guarantee
Security arrangements	Escrow account, one month capacity charges, and a stand-by Letter of Credit, covering three months billing (although only finalized at end-2006)
Project tender, COD	1996, 2000
Contract change	Yes, tariff for the second phased (35 MW) reduced
Fuel arrangement	The only fuel arrangement per se is that OrPower4 leases the wells from the government, to which it pays a royalty of sorts

Kenya (4 of 4 projects)

Project	Tsavo
Size	75 MW
Cost	US\$85 million
\$ per kW	US\$1,133
Technology	HFO/medium speed diesel engine
ICB	Yes
Contract	BOO, 20 years
Debt/Equity	78/22
DFI in equity and debt	Yes (equity and debt)
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	Cinergy & IPS jointly owned 49.9%, Cinergy sold to Duke Energy in 2005, CDC/Globelec (UK, 30%), Wartsila (Finland, 15%), IFC (5%) retain remaining shares since 2000
Lenders	IFC own account (US\$16.5 million), IFC syndicated (US\$23.5 million); CDC own account (US\$13 million); DEG own account (€11 million), DEG syndicated (€2 million)
Credit enhancements	Letter of Comfort provided by government
Security arrangements	Escrow account, equivalent to 1 month capacity charge, and a stand-by Letter of Credit, equivalent to 3 months billing
Project tender, COD	1995, 2001
Contract change	None, but was pressured to lower tariff
Fuel arrangement	Tsavo buys fuel and passes cost through to KPLC based on the units generated and specific consumption parameters agreed on in the PPA

Tanzania (1 of 3 projects)

Project	IPTL
Size	100 MW
Cost	US\$120 million
\$ per kW	US\$1,200
Technology	HFO/medium speed diesel engine
ICB	None
Contract	BOO, 20 years
Debt/Equity	70/30
DFI in equity and debt	None
Local participation in equity and debt	Yes (equity)
Equity partners (country of origin & % of each shareholder)	Mechmar (Malaysia, 70%), VIP (Tanzania, 30% in kind), both have sought to sell shares
Lenders	Two Malaysian-based banks (Bank Bumiputra Malaysia Berhad--now Bank Bumiputra Commercial Bank--and SIME Bank)
Credit enhancements	Sovereign guarantee
Security arrangements	Liquidity facility equivalent to 4 months capacity charge (but not yet established)
Project tender, COD	1997, 1998
Contract change	Yes, post arbitration, monthly capacity charges lowered from US\$3.6 million to US\$2.6 million
Fuel arrangement	IPTL imports fuel, which is a pass through to the utility

Tanzania (2 of 3 projects)

Project	Songas
Size	180 MW ³³⁹
Cost	US\$316 million ³⁴⁰
\$ per kW	US\$2,313 (for first 115 MW) and US\$769 (for 65 MW expansion)
Technology	Natural gas/open cycle
ICB	Yes
Contract	BOO, 20 years
Debt/Equity	70/30 for 115 MW 100% equity financed for 65MW expansion
DFI in equity and debt	Yes
Local participation in equity and debt	Yes (TANESCO, TDFL)
Equity partners (country of origin & % of each shareholder)	TransCanada sold majority shares to AES (USA) in 1999 and AES sold majority shares to Globeleq (UK) in 2003 ³⁴¹
Lenders	World Bank (US\$136 million), EIB, (US\$55 million), Sida, (US\$15 million)
Credit enhancements	None
Security arrangements	Escrow account: for first 115 MW, with the government matching every US\$1 spent by the project company; liquidity facility equivalent to 4 months capacity charge for the first 3 years, declining to 2 months starting in year 4 through the remaining years of the contract
Project tender, COD	1994, 2004
Contract change	Yes, the buying down of Songas' AFUDC (of approximately US\$103 million) by the Government of Tanzania cut the monthly capacity charge by about one third. ³⁴²
Fuel arrangement	Songo Songo gas provided to project company at a rate of US\$0.55/MMBtu for turbines I-V and at US\$2.17 MMBtu for turbine VI

³³⁹There was considerable evolution in terms of the planned capacity for the plant, from 60 MW to the current 180 MW.

³⁴⁰Songas project costs include refurbishment of gas wells, a new gas processing facility, pipeline construction and fuel conversion of the existing power station (Ubungu), in total amounting to US\$266 million, and an additional US\$50 million for expansion in terms of two additional turbines (total 65 MW) and related infrastructure. The expansion was financed entirely by equity. A rough estimate for the electricity generation component would be 40 per cent of project costs or US\$130 million, based on US\$35 million for refurbishment and fuel conversion of existing turbines, US\$45 million assumed loans on existing turbines, and US\$50 million for expansion.

³⁴¹Due to complexity, turnover is detailed in this footnote: Ocelot (Canada), TransCanada (Canada), TPDC (Tanzania), TANESCO (Tanzania), TDFL (Tanzania, sponsored by EIB), IFC (multilateral), DEG (German), CDC (UK) were shareholders by 1996, with TransCanada the majority shareholder; IFC and DEG sold shares to CDC in 1997/8; TransCanada sold shares to AES (USA) in 1999; Ocelot/PanOcean sold shares to AES in 2001; AES sold majority shares to Globeleq (UK) and FMO (Holland) in 2003. *After the AES sale, equity shares and associated financial commitments (expressed in US\$ million) in Songas were as follows: Globeleq: US\$33.8 (56%); FMO: US\$14.6 (24%); TDFL: US\$4 (7%); CDC: US\$3.6 (6%); TPDC: US\$3 (5%) and TANESCO: US\$1 (2%). This does not reflect the additional US\$50 million that Globeleq committed for the expansion.*

³⁴²The buying down of the AFUDC, which was negotiated by the Government of Tanzania during AES's sale to Globeleq, has not, however, negatively impacted on the sponsor since the full amount of the buy-down was paid to Globeleq. In addition, since May 2005, TANESCO has not been paying the portion of the capacity charge that relates to the project's subordinated debt. Although such an arrangement was provided for in the subsidiary loan agreement of 2001, what this means is that the IDA credit that the Government of Tanzania on-lent to TANESCO at a higher rate is presently not being serviced by the utility.

Tanzania (3 of 3)

Project	Mtwara Energy Project
Size	12 MW
Cost	US\$ 8.2 million
\$ per kW	US\$683
Technology	gas-fired reciprocating engine
ICB	None
Contract	BOO, 2 years (20 years expected)
Debt/Equity	100% financed with balance sheet of shareholders to date
DFI in equity and debt	Yes (equity)
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	Artumas (Canada, 80%), FMO (Netherlands, 20%)
Lenders	100% financed with balance sheet of shareholders to date
Credit enhancements	None
Security arrangements	Escrow account during interim PPA (2 years), during 20 year PPA, Tariff Equalization Fund expected, a fixed-value account designed to make up the difference between the national tariff and the cost of power under the project
Project tender, COD	1994, 2007
Contract change	None
Fuel arrangement	Fuel provided by sponsor, at a charge of US\$5.00 per MMBtu, which is passed through to utility

West Africa
Cote d'Ivoire (1 of 2)

Project	Compagnie Ivoirienne de Production d'Electricité (CIPREL)
Size	210 MW
Cost	US\$105.6 million ³⁴³
\$ per kW	US\$503
Technology	Natural gas/open cycle
ICB	None
Contract	BOOT, 19 years
Debt/Equity	-
DFI in equity and debt	Yes (equity and debt)
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	SAUR International, with 88% (JV between French SAUR Group owned by Bouygues, 65% and EDF, 35%) BOAD, PROPARCO, and IFC holding the remaining 12%; in 2005 all shares sold to Bouygues (France, 98%), except BOAD (2%)
Lenders	World Bank
Credit enhancements	None
Security arrangements	None
Project tender, COD	1993, 1995
Contract change	None
Fuel arrangement	Government procures fuel

³⁴³ Investment cost €87.8m or 57.6 billion CFA, with the average 1994 conversion of US\$ to CFA, 545,100.

West Africa

Cote d'Ivoire (1 of 2)

Project	Compagnie Ivoirienne de Production d'Electricité (CIPREL)
Size	210 MW
Cost	US\$105.6 million ³⁴³
\$ per kW	US\$503
Technology	Natural gas/open cycle
ICB	None
Contract	BOOT, 19 years
Debt/Equity	-
DFI in equity and debt	Yes (equity and debt)
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	SAUR International, with 88% (JV between French SAUR Group owned by Bouygues, 65% and EDF, 35%) BOAD, PROPARCO, and IFC holding the remaining 12%; in 2005 all shares sold to Bouygues (France, 98%), except BOAD (2%)
Lenders	World Bank
Credit enhancements	None
Security arrangements	None
Project tender, COD	1993, 1995
Contract change	None
Fuel arrangement	Government procures fuel

³⁴³ Investment cost €87.8m or 57.6 billion CFA, with the average 1994 conversion of US\$ to CFA, 545,100.

Ghana (1 of 1)

Project	Takoradi II
Size	220 MW ¹⁴⁵
Cost	US\$ 110 million
\$ per kW	US\$500
Technology	Light crude oil/single cycle
ICB	None
Contract	BOOT, 25 years
Debt/Equity	Financed exclusively with balance sheet of sponsors
DFI in equity and debt	No
Local participation in equity and debt	Yes (equity)
Equity partners (country of origin & % of each shareholder)	CMS (USA, 90%), VRA (Ghana, 10%), CMS sold shares to TAQA (UAE, 90%) in 2007
Lenders	Financed exclusively with balance sheet of sponsors
Credit enhancements	Sovereign guarantee
Security arrangements	US\$ 3 million Letter of Credit provided by government
Project tender, COD	1998, 2000
Contract change	Failure to develop 2 nd phase (110 MW), investors cite the lack of government guarantees (granted in the first phase of Takoradi II) meanwhile government has indicated that the EPC costs are too high and further development remains at standstill
Fuel arrangement	Government procures fuel

¹⁴⁵ The initial project concept included specifications to add a second phase of 110 MW and convert to combined cycle, however, lack of funding has limited the completion of this phase.

Nigeria (1 of 2)

Project	AES Barge Limited
Size	270 MW
Cost	US\$240
\$ per kW	
Technology	Natural gas/open cycle (barge mounted)
ICB	None
Contract	BOO, 20 years
Debt/Equity	NA
DFI in equity and debt	None
Local participation in equity and debt	Yes (equity)
Equity partners (country of origin & % of each shareholder)	Enron (USA, 100%) sold to AES (95%) and YFP (Nigeria, 5%) in 2000
Lenders	NA
Credit enhancements	OPIC political risk insurance Sovereign guarantee
Security arrangements	US\$60 million Letter of Credit from Ministry of Finance
Project tender, COD	1999, 2001
Contract change	Yes, initial plant size increased from 90 MW to 270 MW (9 units of 30 MW each) and change in the fuel from liquid fuel to natural gas, both of which had the effect of reducing the capacity charge, current contract changes under discussion involve among other things the availability deficiency payment, meanwhile tax exemption certificate has been withheld by government for the duration of the project
Fuel arrangement	Utility arranges fuel

Nigeria (2 of 2)

Project	Okpai
Size	450 MW
Cost	US\$ 462 ³⁴⁶
\$ per kW	
Technology	Natural gas/combined cycle
ICB	None
Contract	BOO, 20 years
Debt/Equity	100% equity financed
DFI in equity and debt	None
Local participation in equity and debt	Yes (equity and debt)
Equity partners (country of origin & % of each shareholder)	Nigerian National Petroleum Corporation (Nigeria, 60%), Nigerian Agip Oil Company (Italy, 20%), and Phillips Oil Company (USA, 20%) maintained equity since 2001
Lenders	Provided by equity partners
Credit enhancements	PPA backed by Nigerian Petroleum Development Company's oil revenues
Security arrangements	None
Project tender, COD	2001, 2005
Contract change	Ongoing negotiations related to investment costs which rose by US\$150 million, to US\$462 million; although plant is producing power, due to the dispute, full payment is not being made by utility
Fuel arrangement	Project company provides fuel

³⁴⁶ Project costs include the gas infrastructure.

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